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AZ CORP COMMISSION
DOCKET CONTROL

SolarCity

October 9, 2015

Commissioner Tom Forese
Arizona Corporation Commission
1200 W. Washington Street
Phoenix, Arizona 85007

Re: Docket No.: E-00000J-15-0347

Dear Commissioner Forese:

SolarCity appreciates the invitation to present to the ACC in the upcoming workshop on October 14th. While we believe it is worthwhile for you and other Commissioners and staff of the ACC to understand our company's challenges and vision for the future, we will not be able to participate in the meeting.

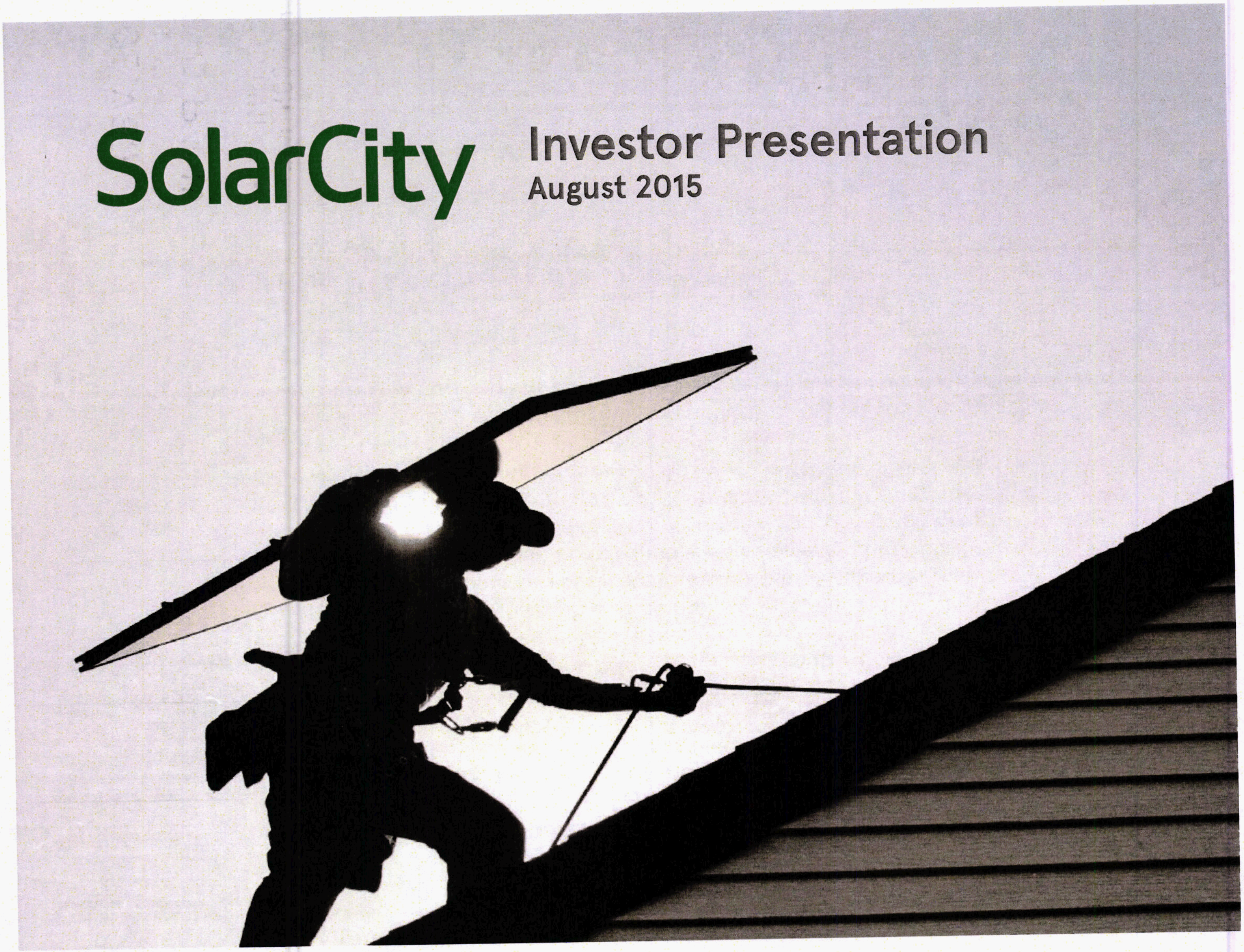
In an effort to be responsive to your inquiry and provide you with an overview of SolarCity, I submit the following information as public comment:

- SolarCity's August 2015 Investor Presentation, which provides a high-level look at the company, as well as current opportunities and challenges.
- A filing in the State of New York's Reforming the Energy Vision docket and link below to the docket itself which includes more details of our vision for the future of distributed energy resources and for revising the regulatory compact, as well as the comments of others (http://www.ny.gov/programs/reforming-energy-vision).

SolarCity currently employs more than 13,000 workers nationwide. Almost 750 people work in our company warehouses located in North and South Phoenix, Gilbert, Mesa, the Prescott Valley, Tucson and South Tucson, the West Valley and Yuma. The 25,000-plus SolarCity installations across the state have produced over .5 terawatt hours of electricity thus far.

Thank you,

Thad Kurowski
Director of Policy & Electricity Markets


SolarCity
Investor Presentation
August 2015

Forward-Looking Statements

This presentation contains forward-looking statements that involve risks and uncertainties, including statements regarding SolarCity's customer and market growth opportunities; SolarCity's operational growth and expansion; financial strategies for cash generation and increasing shareholder value; the deployment and installation of megawatts including estimated Q3 2015 megawatt installations; future bookings; our plans to vertically integrate our commercial product offerings, and resulting anticipated cost and operational efficiencies; GAAP revenue, gross margin, operating expenses and non-GAAP EPS for Q3 2015; Estimated Nominal Contracted Payments Remaining; forecasted Net Retained Value; Economic Value Creation and Unlevered IRR of Q2 2015 megawatts deployed; cash flows and PowerCo Available Cash forecast; cost goals by 2017; customer goal for 2018; forecasted access to capital; the amount of megawatts that can be installed and deployed based on committed available financing; expected future GAAP and non-GAAP operating results; and assumptions relating to the foregoing.

Forward-looking statements should not be read as a guarantee of future performance or results, and will not necessarily be accurate indications of the times at, or by, which such performance or results will be achieved, if at all. Forward-looking statements are subject to risks and uncertainties that could cause actual performance or results to differ materially from those expressed in or suggested by the forward-looking statements. In order to meet our projections, we will need to expand our workforce, increase our installation efficiency and exceed our existing bookings rate relative to what we have achieved to date. Additional key risks and uncertainties include the level of demand for our solar energy systems, the availability of a sufficient, timely, and cost-effective supply of solar panels and balance of system components, our ability to successfully integrate Silevo, LLC's business, operations and personnel and achieve manufacturing economies of scale and associated cost reductions, our expectations regarding the Riverbend agreement and the development and construction of the Riverbend facility, including expected capital and operating expenses and the performance of our manufacturing operations, the effects of future tariffs and other trade barriers, changes in federal tax treatment, the effect of electric utility industry regulations, net metering and related policies, the availability and amount of rebates, tax credits and other financial incentives, the availability and amount of financing from fund investors, the retail price of utility-generated electricity or the availability of alternative energy sources, risks associated with SolarCity's rapid growth, risks associated with international expansion, the success of our product development efforts and customer preferences, risks that consumers who have executed energy contracts included in reported nominal contracted payments remaining and backlog may seek to cancel those contracts, assumptions as to retained value under energy contracts and contract renewal rates and terms, assumptions as to leveraged retained value and MyPower retained value, including applicable net present values, performance-based incentives, and other rebates, credits and expenses, SolarCity's limited operating history, particularly as a new public company, changes in strategic planning decisions by management or reallocation of internal resources, completion of preparation of financial statements and general market, political, economic and business conditions. You should read the section entitled "Risk Factors" in our most recent Quarterly Report on Form 10-Q and subsequent Current Reports on Form 8-K, which have been filed with the Securities and Exchange Commission, which identify certain of these and additional risks and uncertainties. We do not undertake any obligation to publicly update or revise any forward-looking statement, whether as a result of new information, future developments or otherwise, except as otherwise required by law.

Our Vision

To transform the way energy is delivered in the 21st century through cleaner, more affordable distributed solar energy

Clean, More Affordable Energy

We Lower Customers Energy Bills by Providing Solar Energy for No Initial Investment

- No Upfront Cost for Installation
- Solar energy paid for monthly at a lower $/kWh price than charged by the local utility
- Customers generate savings from Day One

See Appendix slides for footnotes and relevant definitions

Residential Is a Huge and Underpenetrated Opportunity

Total Addressable Opportunity in Our Current Markets Exceeds 240 GW with Total U.S. > 550 GW

Residential Represents 1.1 GW or 77% of Our Cumulative MW Installed as of the End of Q2 2015

In millions	Current Markets	Total U.S.
Customer Goal by Mid-2018	1.0M	1.0M
/ Total Single Family Housing Units [1]	41.3M	92.2M
= Penetration of Single-Family Homes	2.4%	1.1%

Residential Contracts Extend for 20-30 Years

- Average residential system size: ~6 kW
- Our solar contracts typically generate 50-90% of a customer's annual electricity needs and lower their total bill by ~20%
- New Energy Contract pricing is based on a discount to utility rates at the time of booking with an annual escalator of <3%

A Growing, Untapped Opportunity

- >40M single-family homes in our 19 states and >92M across the country
- Over 53% of the U.S. population has FICO score above 700 (and 66% over 650)[2]
- Additional opportunity across the U.S. and internationally

Commercial Segment Presents an Enormous Opportunity

We Installed More U.S. Commercial/Government Solar Capacity in 2014 than Any Other Provider

Over 2,000 Commercial and Government Customers and >320 MW Installed as of the End of Q2 2015

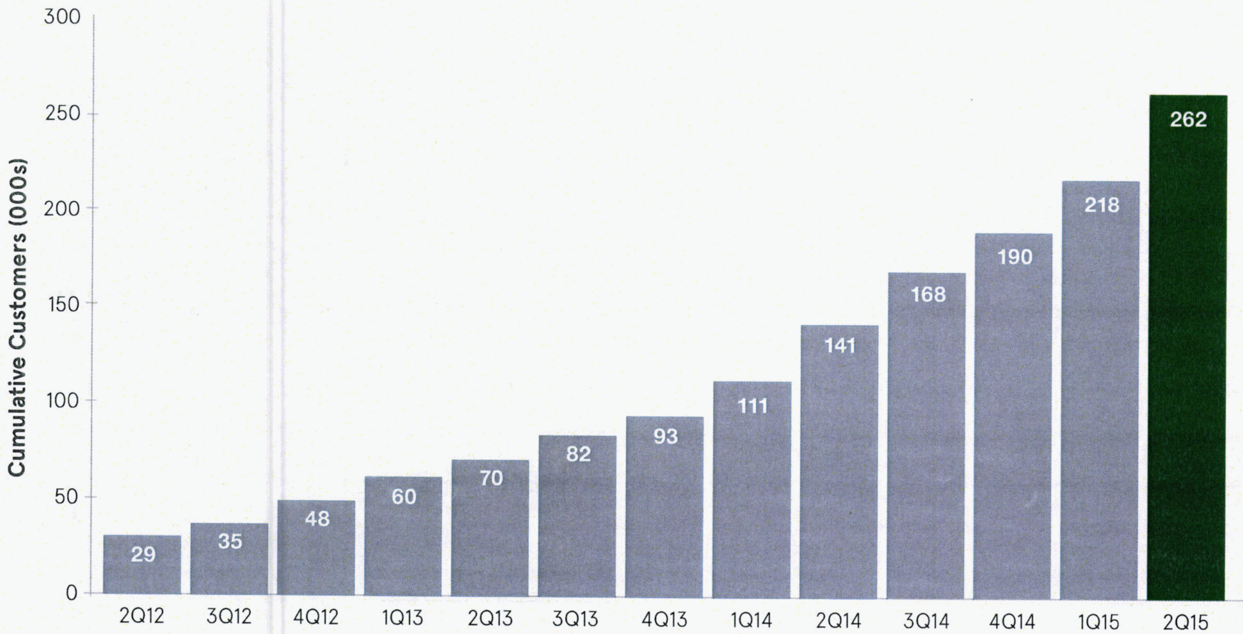
Commercial and Government Customers Value Lower Costs and Budget Visibility

- Our commercial system sizes can range from as small as 20 kW to 5 MW or more
- Customers include DirectTV, eBay, HP, Intel, Safeway, Walgreens, Wal-Mart, and >400 schools
- ZS Peak patented mounting system enables more panels per square foot and quicker installation
- DemandLogic commercial storage solution helps customers avoid costly demand charges
- With <1% solar penetration of the 5.6M commercial buildings in the U.S.[3], opportunity is vast

Goal of One Million Customers by Mid-2018

Less than 250k New Customers per Year Required to Meet Our Goal over the Next 3 Years

Goal Implies a Compounded Growth Rate of 56% vs. Recent Historical Pace of 97% Since 2012



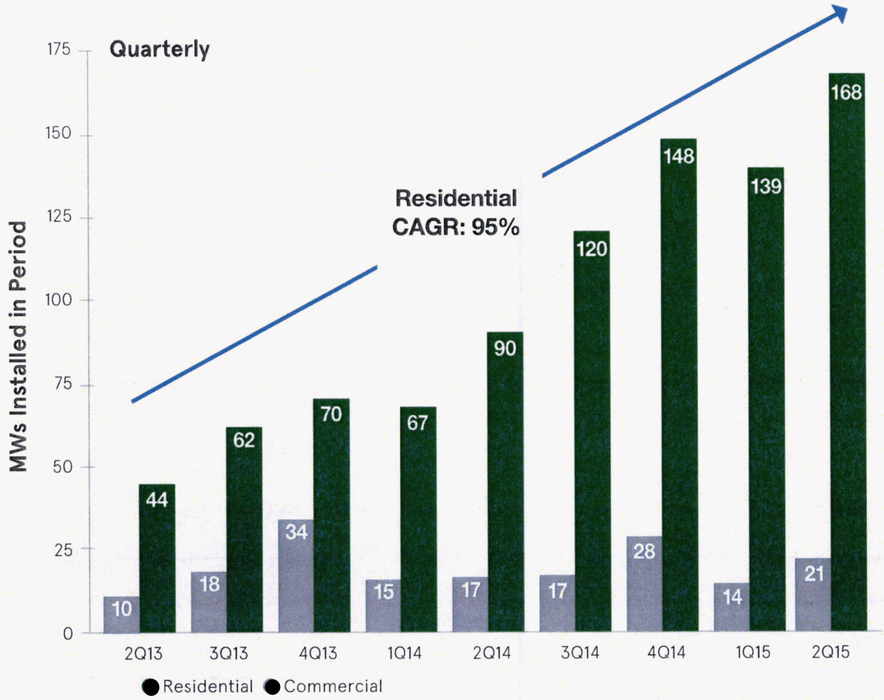
** Figures on page may not calculate exactly due to rounding*

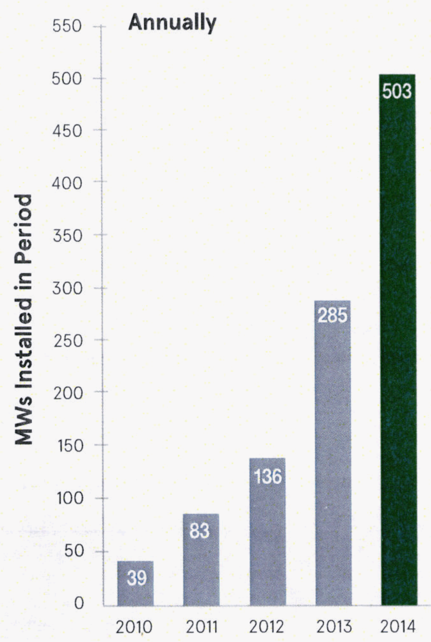
See Appendix slides for footnotes and relevant definitions

1.4 GW Installed at the End of Q2 2015

Cumulative MW Installed Have Grown at a Compounded Rate of 96% since 2010

Latest Guidance Is to Install 920 – 1,000 MW in 2015*





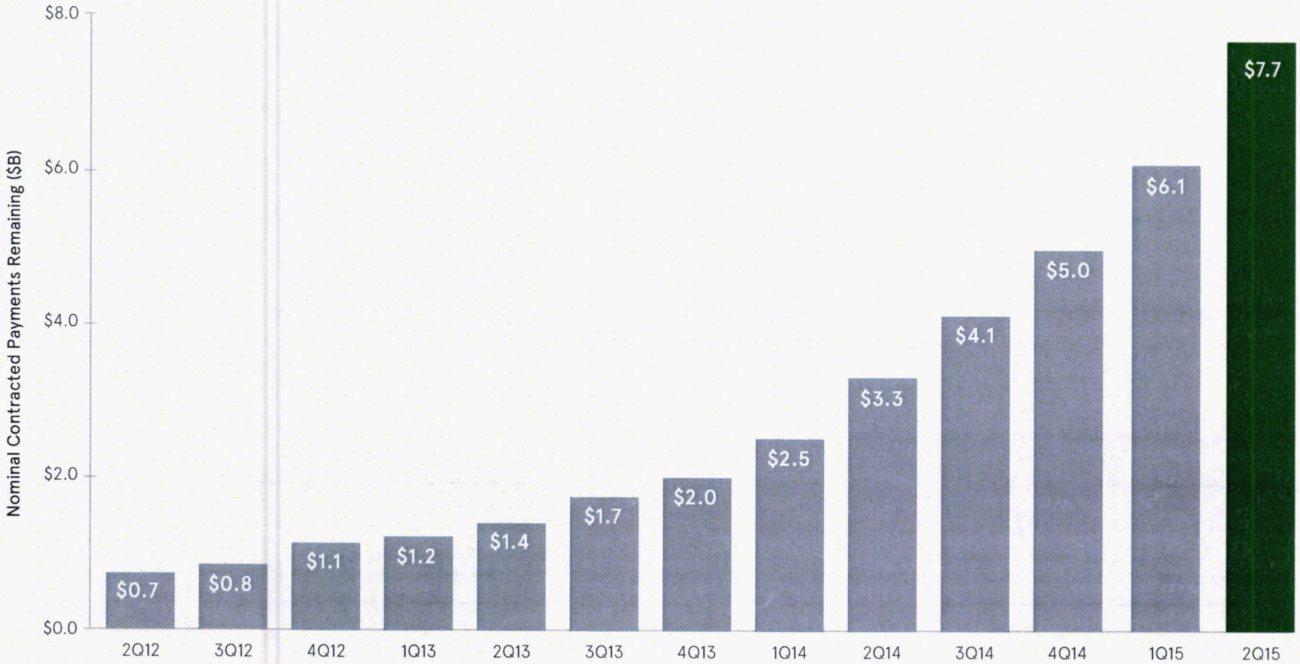
*Represents the Company's estimate as of July 29, 2015

See Appendix slides for footnotes and relevant definitions

Contracted Customer Payments at $7.7B

High Visibility into Revenue with Contracts of 20 years for Leases/PPAs and 30 Years for Loans

Nominal Contracted Payments Remaining Increased by a Net $3.0B in 2014 and $2.7B in 2015 YTD



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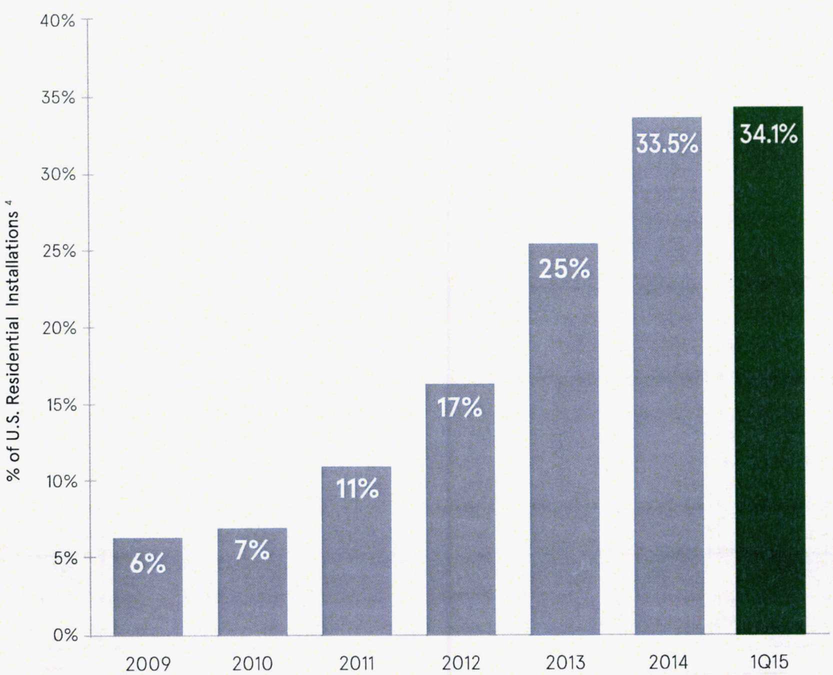
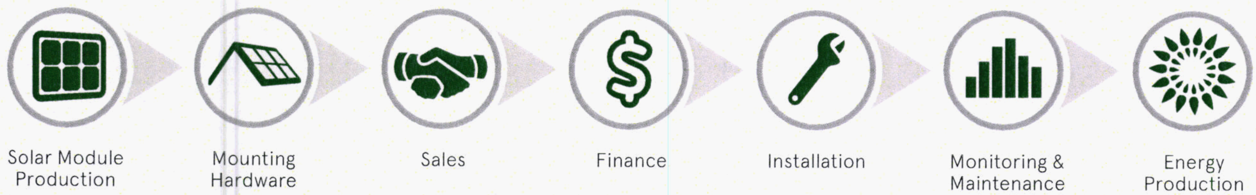
The Clear Leader in U.S. Residential Installations



Our residential MW installations exceeded the next 34 competitors' combined in Q1 2015 (the most recent data available)

See Appendix slides for footnotes and relevant definitions

Vertical Integration Provides Best Product at Lowest Cost

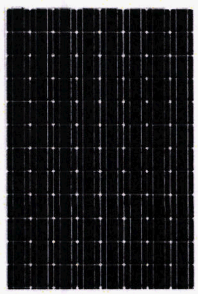


- **One out of every three** new U.S. residential solar customers chooses SolarCity
- **Largest U.S. company by a wide margin** with more customers than any other provider, >12,000 Employees including thousands of Installers, and >75 operations centers across 19 states as of Aug 2015
- **Diversified Sales Channels** from our direct sales force to channel partnerships including home builders, Home Depot, DirecTV, Best Buy, among others
- **Strong Project Financing Track Record** with deals in place to finance more than $8.4 billion in distributed solar installations to date
- **Top Quality Installations** with industry's only fully integrated product from patented hardware manufacturing to post-contract service enabling high quality product with superior aesthetics
- **High Customer Satisfaction** as evidenced by > 20% of our new customers in 2013-14 coming from referrals

Broad Technology Portfolio

Solar Modules

- Triex Tunneling Junction
- High efficiency / low cost
- 24% target cell efficiency

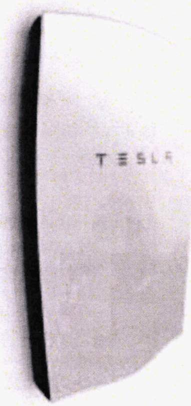


Mounting hardware and Balance of System

- Fast installation, lower cycle time
- Superior aesthetics

Software

- System design automation
- Energy production forecasting
- Logistics and resource management
- Utility rate tariff database
- Energy usage evaluations
- Customer account management
- Customer applications



Grid Control Systems

- Real-time energy monitoring
- Voltage control
- Energy storage integration

Strong Track Record of Regulatory Collaboration to Expand Solar Markets

Favorable Solar Policy Continues to Expand Across the U.S. Despite Negative Media Coverage

Recent Positive Regulatory Developments

- CA mandated streamlining of local solar permitting, extended the property tax exclusion for solar by 8 years, and is developing an uncapped NEM 2.0 program.
- NY doubled the NEM cap to 6% in Dec. 2014 and a comprehensive REV docket seeks to appropriately value clean energy / distributed solar
- MA has no residential NEM cap
- HI utility interconnection restrictions eased after pilot project supported a doubling of circuit capacity
- Additional markets have opened up, including SC as the 44th state to adopt a statewide NEM policy

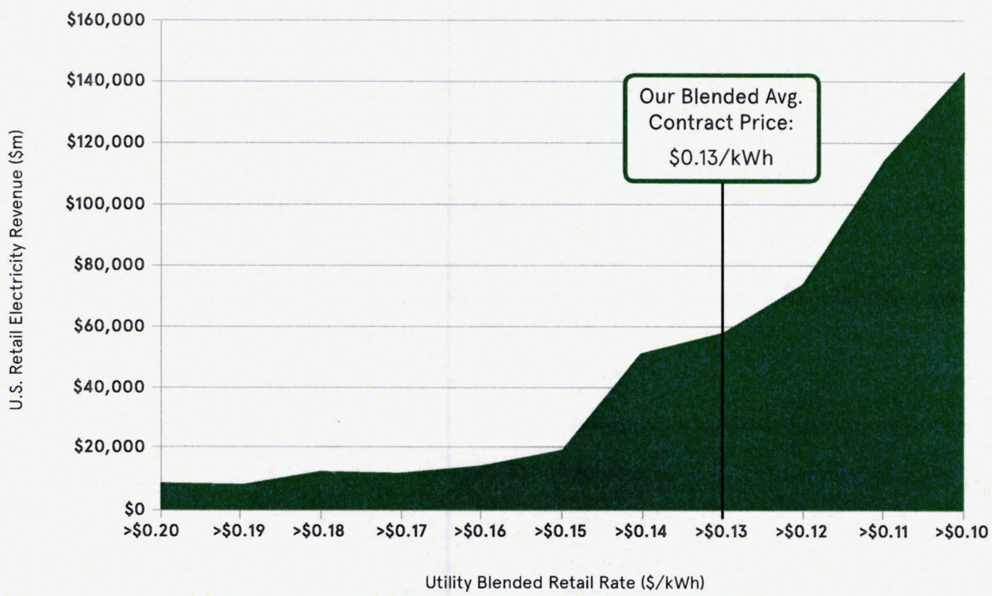
Only Significant Regulatory Setback

- SRP implemented anti-solar rate design changes (though existing installations were grandfathered in with no fee)

Total Addressable Market in U.S. of ~$60b and Growing

At Our Blended Contract Price of ~$0.13/kWh, U.S. Retail Electricity Sales Are Close to $60B[5]

Addressable Market Expands as Our Costs Continue to Trend Lower and Retail Utility Rates Rise



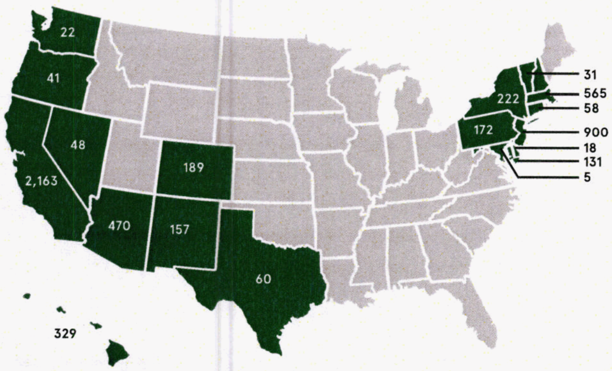
See Appendix slides for footnotes and relevant definitions

Economics Driven by Costs, Utility Rates, and Sun

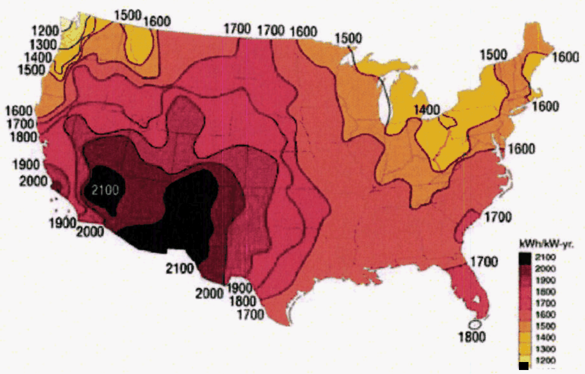
The U.S. Has Installed 5.4 GW of Residential/Commercial Solar in Our 19 States since 2011[6]

Lower Costs and Rising Utility Rates Broaden Distributed Solar's Target Market

Industry-wide MW Solar Installed 2011-2014 in Our 19 States



Solar Insolation Levels Make Many Other States Viable



Drivers of Distributed Solar's Returns

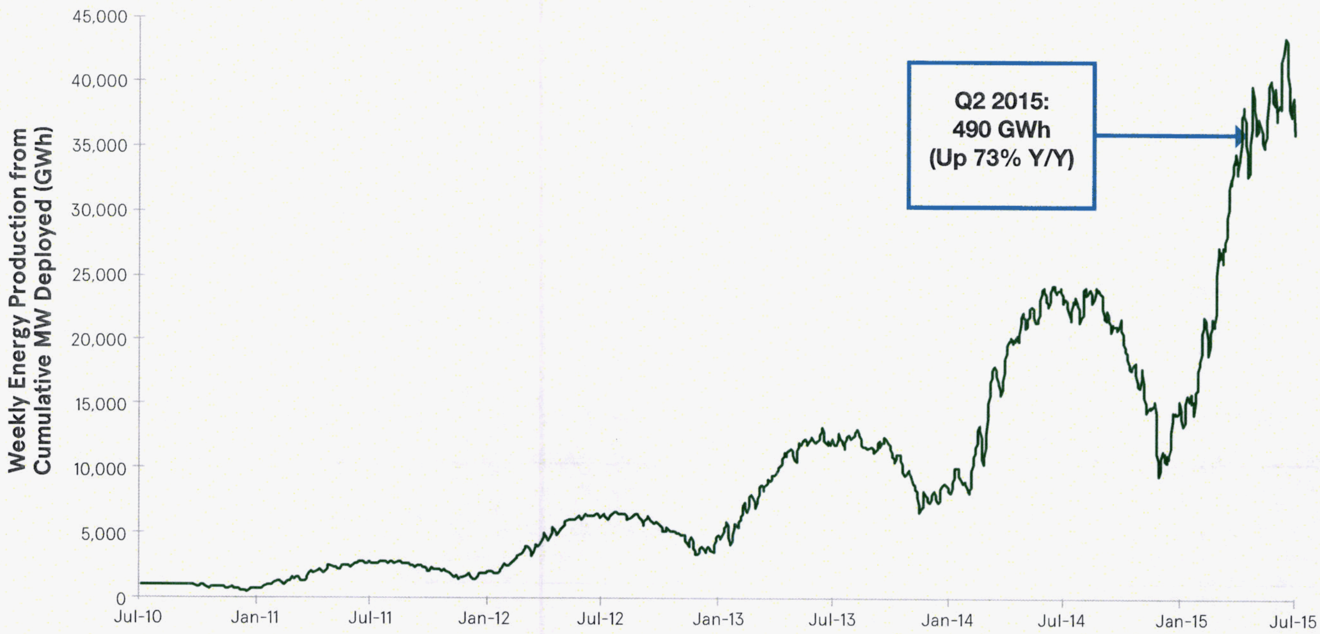
- Retail electricity price
- Cost to develop/install solar
- Annual hours of sun

See Appendix slides for footnotes and relevant definitions

1.25 TWh of Energy Production over Trailing 12 Months

Record Day of 6.5 GWh in Energy Production Achieved in June 2015

Energy Production Is Seasonal along with Sun-Hours and Tends to Reach Annual Highs in Q2 and Q3



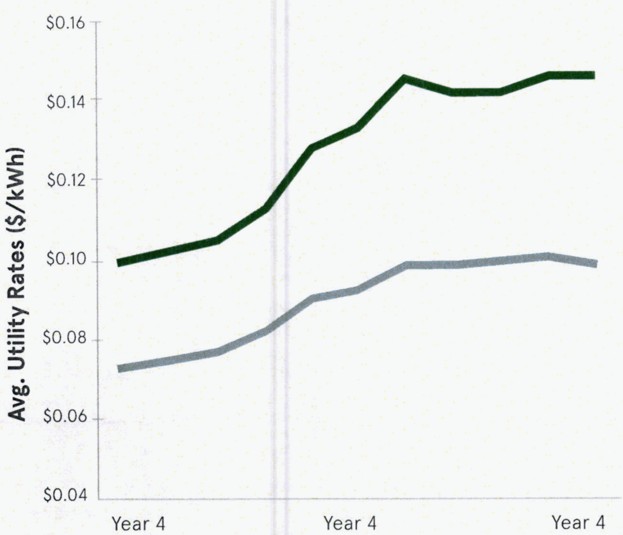
See Appendix slides for footnotes and relevant definitions

Strong Tailwinds from Rising Utility Rates

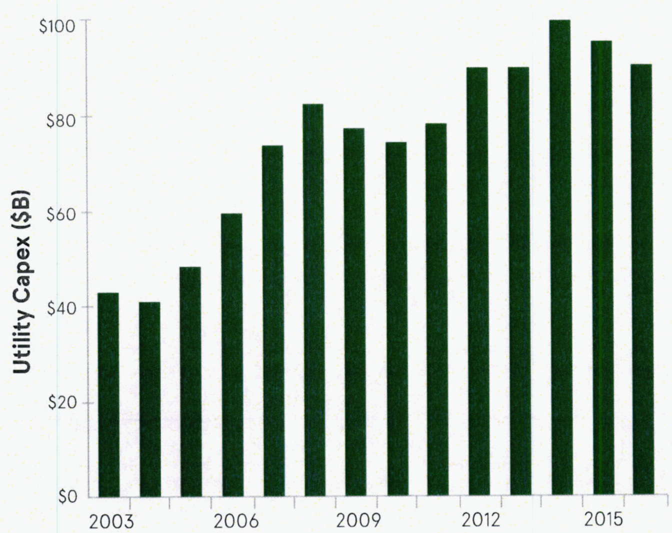
Outlook for Growing Utility Infrastructure Capex Points to Further Increases in Utility Rates

Higher Utility Rates Increase the Total Value Created by Distributed Solar

Utility Rates in Our Markets Are Up 47% since 2002[7]



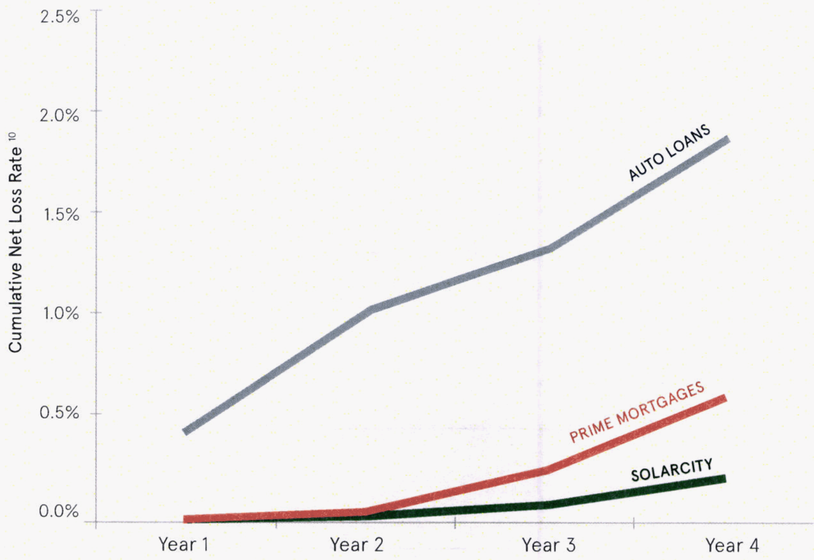
$100B Utility Capex Forecast in 2015 Up >100% since 2003[8]



Average U.S. Retail Electricity Rates Have Continued to Rise Over the Last Few Years Even as Natural Gas Prices Have Fallen to Recent Lows[9]

High Margin Revenue Stream from Long-Term Contracts

Each Customer Provides a Visible Cash Flow Stream akin to the Household Utility Bill Payment



Consistent Annuity-Like Cash Flow Stream

- Long-term contracts of 20 years for residential PPAs/leases and 30 years for MyPower loans
- Net loss rates better than mortgages to date
- High FICO scores with cumulative average >735
- Low ongoing annual O&M expenses of ~$0.02/W with inverter replacements every 10 years

Strong Contract Payment Performance

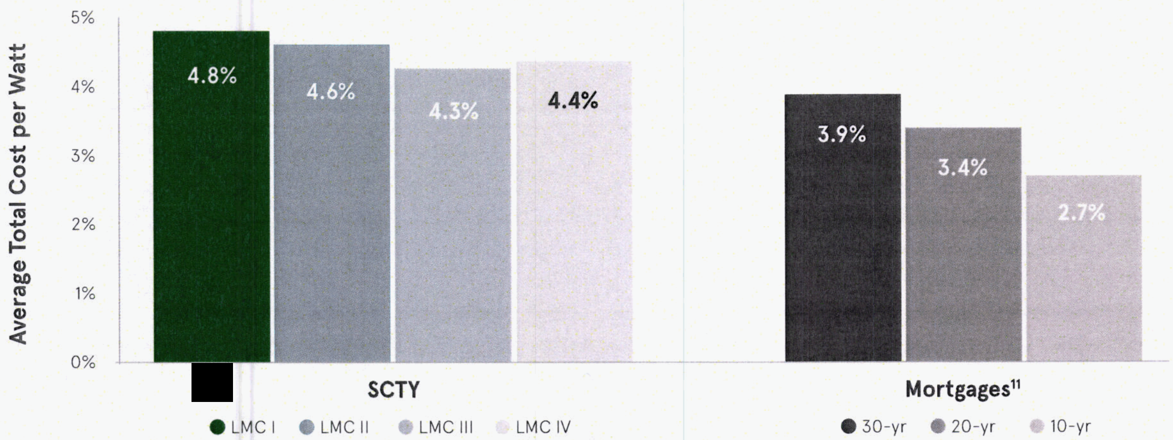
- When customers sell their homes, we transfer the solar contract to the new owner 98% of the time
- Roof replacements made easy for low fee

See Appendix slides for footnotes and relevant definitions

Low Cost of Capital with Spreads Expected to Compress

First Asset-Backed Securitizations Have Secured Low Cost Debt Financing <5% for 8-13 Year Duration

Since Energy Bills Are Among the First Household Bills Paid, We Expect Risk Premiums to Converge with Mortgages



Visibility and Predictability of Long-Term Recurring Cash Flows Yielding Lower Cost of Capital:

- ABS cost of 4-5% is >100 basis points below the 6% discount rate we use in our NPV and Retained Value forecasts
- Class A notes of most recent securitization was rated Single A
- Declining risk premium expected to help offset potential increases in the risk free rate
- Higher interest rates tend to have inflationary impact on utility rates
- Evaluating interest rate hedging products to further manage risk

Scale and Efficiencies Driving Costs to New Lows

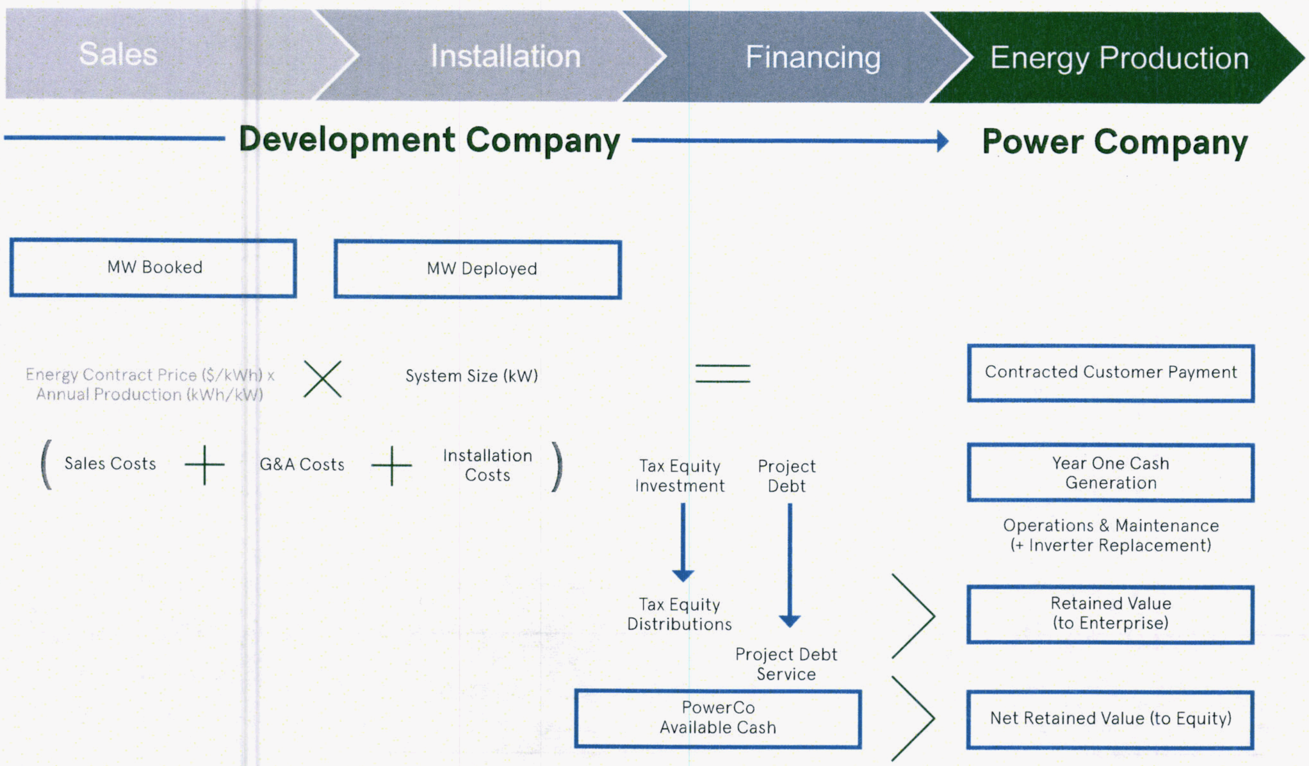
Goal for Total Cost of $2.50/W and Installation Cost of $1.90/W by 2017 Well Within Reach

Our Total Cost per Watt Has Declined at a Compounded Annual Rate of (11%) Since the End of 2012

See Appendix slides for footnotes and relevant definitions

Figures may not add due to rounding

Our Value Creation Chain



Economic Value Creation of $196M in Q2 2015

Net Present Value Forecast of $196M to Equity after Forecasted Debt on Q2 2015 Deployments

Debt Assumes 4.5% Cost at a 68-75% Advance Rate on Cash Flows for 20 Yrs. for Leases/PPAs and 30 Yrs. for MyPower

$ Million	Blended Q2 2015 Deployments	DevCo Investment	PowerCo Cash Flow Forecast		
Project Cash Flow Forecast:		Year 1	Annual Avg. of Tax Equity Period (Yrs. 1 – 6.7)	Annual Avg. of Post-Tax Equity Period (Yrs. 6.7 – 20)	Annual Avg. ,of Remaining Life (Yrs. 20-30)
Customer and PBI Revenue	1,380 kWh/kW (-0.5% / Yr.) x $0.13/kWh (@ 2.2% esc.)		$33M	$40M	$47M
SREC Revenue	Blended Contracted		$4M		
Upfront Development Investment	172 MW x $2.91/W	($500M)	$-	$-	$-
State Rebates and Prepayments	Blended average across portfolio	$17M	$-	$-	$-
Operations & Maintenance Costs	$0.02/W (+ 2.5% / Yr.)		($4M)	($7M)	($8M)
Gross Project Cash Flow Forecast		**($483M)**	**$33M**	**$33M**	**$39M**
Project Financing:					
Tax Equity Lease/PPA Investment and Distributions	30-40% Pre-Flip; 7% Post-Flip	$260M	($9M)	($2M)	($2M)
PowerCo Unlevered Project Cash Flow Forecast		**($223M)**	**$24M**	**$31M**	**$37M**
Forecasted Non-Recourse Debt	4.5% interest rate	$206M	($14M)	($16M)	$-
PowerCo Available Cash Forecast		**($17M)**	**$9M**	**$15M**	**$37M**

Unlevered IRR of 12%

30-Yr. NPV of $196M ($138M contracted/$58M renewal) or $1.14 per Watt] at 6% discount rate

** Figures on page may not calculate exactly due to rounding*

See Appendix slides for footnotes and relevant definitions

PowerCo Available Cash of $114M over Last 12 Months

PowerCo Available Cash Represents the Net Cash Flows Generated by Installed Energy Contracts

Excluding DevCo Installation/Sales/G&A Costs, It Represents Our Cash Flow Assuming No New Development

Trailing Twelve Months through June 30, 2015	$M
PowerCo Operating Cash Flow	**$200**
- Distributions to Tax Equity Partners	($52)
= PowerCo Unlevered Cash Flow	$148
- Principal Repayment on PowerCo Debt	($17)
- Interest Payments on PowerCo Debt	($17)
PowerCo Available Cash	**$114**
+ Distributions to Tax Equity Partners	$52
Normalized PowerCo Available Cash (Post-Tax Equity Buyout)	**$166**

Excluding tax equity distributions which we expect to fall off after the remaining ~7 year lives of our tax equity funds, Normalized PowerCo Available Cash was $166 million

>$3B in Net Retained Value as of 6/30/15

Net Retained Value Represents Our Discounted Cash Forecast to Equity After Net Debt Outstanding

Assuming No New Contracts or Cancellations, Value Retained by Equity Estimated at $3.1B as of the End of Q2 2015

Forecast at June 30, 2015 ($M)	Total
PPA / Lease Energy Contract (6% discount rate)	*$2,381*
PPA / Lease Renewal (6% discount rate)	*$941*
MyPower (6% discount rate)	*$495*
Gross Retained Value Forecast (6% discount rate)	**$3,817** [redacted]
- Total Debt Outstanding*	($1,156)
- Forecasted Net Cash Costs to Deploy Backlog[12]	($94)
+ Cash and Short-Term Investments	$489
Net Retained Value	**$3,057**

** Excludes Convertible Debt Outstanding of $796 Million as It Is Currently Assumed to Settle in Equity*

Gross Retained Value was $1.81 per Watt at June 30, 2015
with Residential Lease/PPA at $1.89/W, Commercial at $0.90/W, and MyPower at $3.69/W

See Appendix slides for footnotes and relevant definitions

Summary

Power Company

- Investment grade assets
- Low default and net loss rates
- $114M in PowerCo Available Cash TTM through 2Q 2015 ($166M post-flip)
- $3,057M in Net Retained Value (cash coming to SCTY over 30 years less net debt today)

Development Company

- Massive and expanding addressable market
- 34% of U.S. residential and ~8% of U.S. commercial solar installations in 2014
- Lowest all-in unit costs of the industry
- MW Installed growth of 83% per year since 2013
- Guidance for 920 - 1,000 MW Installed in 2015
- 1H15 Economic Value Creation of $343M ($1.11 per watt) with avg. annual cash flow of $0.07/W over 20 years

Questions & Answers

Appendix A: GAAP Income Statement

$ in thousands	Consolidated GAAP Income Statement			
Revenue:	2013	2014	Q2 2014	Q2 2015
Operating leases and solar energy system incentives	$82,856	$173,636	$43,181	$78,283
Solar energy systems and components sales	$80,981	$81,395	$18,153	$24,520
Total revenues	**$163,837**	**$255,031**	**$61,334**	**$102,803**
Cost of revenue:				
Operating leases and solar energy system incentives	$32,745	$92,920	$20,826	$37,392
Solar energy systems and components sales	$91,723	$83,512	$17,635	$22,087
Total cost of revenues	**$124,468**	**$176,432**	**$38,461**	**$59,479**
Gross profit (loss)	**$39,369**	**$78,599**	**$22,873**	**$43,324**
Operating Expenses:				
Sales and Marketing	$97,426	$238,608	$55,771	$113,160
General and Administrative	$89,802	$156,426	$38,387	$50,211
Research & Development	$1,519	$19,162	$3,000	$12,401
Total Operating Expenses	**$188,747**	**$414,196**	**$97,158**	**$175,772**
Loss from operations	**($149,378)**	**($335,597)**	**($74,285)**	**(132,448)**
Operating lease and solar energy system incentive gross margin	***60%***	***46%***	***52%***	***52%***

Customer Payment Revenue

- Primarily represents customer payments recognized as received over the life of the energy contract, typically 20-30 years
- Also includes amortization of rebate/ITC incentive revenue

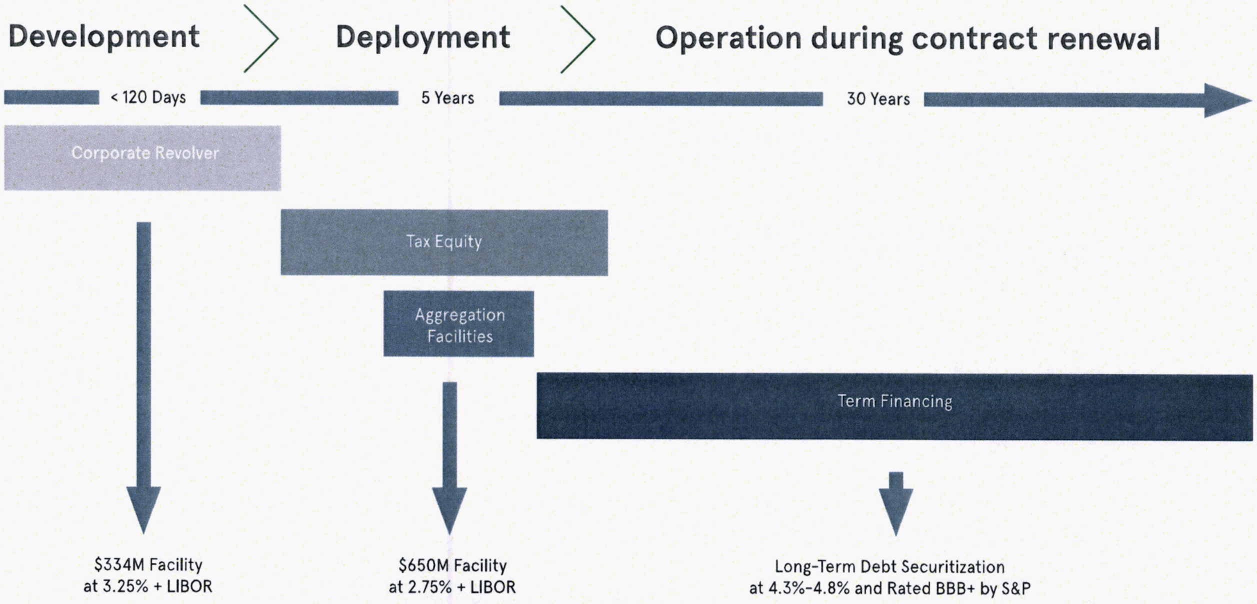
Depreciation and O&M

- Almost entirely composed of depreciation of the capitalized (1) installation costs and (2) variable sales costs of Solar Energy Systems Leased to Customers
- Also includes operations & maintenance expenses at current run rate of ~$0.01/W
- Non-cash amortization of intangibles of $10m in in 2014

Development Investment

- Largely represents investment to support new MWs booked and deployed each period
- GAAP profitability constrained with operating lease revenue recognized over the life of a contract but certain development expenses for MWs booked/deployed booked as incurred

Appendix B: Financing Value Chain



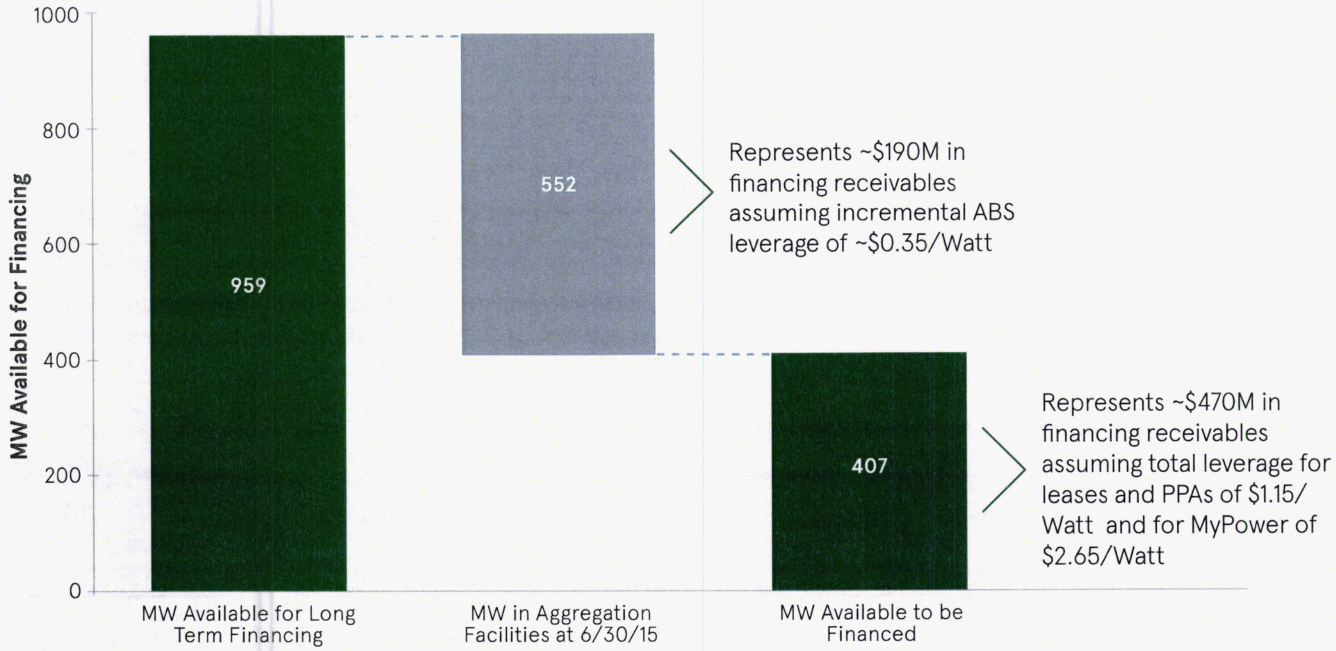
Visibility and Predictability of Long-Term Recurring Cash Flows Yielding Lower Cost of Capital:

- Aggregation facilities and securitization are non-recourse and collateralized by our interests in customer cash flows under contract
- Electric utility bill default rates are historically lower than those of residential mortgage payments
- Continued compression in the risk premium of distributed solar to help offset potential rise in risk free rates

Appendix C: Financing Receivables of ~$660M

Our Cash Generation Is Currently Understated by the Delayed Timing of Financing Cash Flows

Based on Available Deployed Energy Contracts Not Fully Financed, Our "Financing Receivables" Are ~$660M



Appendix D: Footnotes

[1] Single-family housing units based on data from U.S. Census 2013 American Community Survey's "Housing Units by Units in Structure and State: 2013" and assumes 1.0% annual growth in the housing stock per year through 2015. Excludes multi-family, mobile, and other housing units.

[2] Fair Issac Corporation October 2013

[3] Commercial buildings count from EIA's 2012 Commercial Buildings Energy Consumption and commercial solar installations SEIA (Solar Energy Industries Association) and Greentech Media's "U.S. Solar Market Insight Report" as of the end of 2014.

[4] GTM Research – U.S. PV Leadership Board

[5] "Electric Sales, Revenue, and Price" from EIA's Electric Power Annual 2013 report (http://www.eia.gov/electricity/data.cfm#sales)

[6] SEIA (Solar Energy Industries Association) and Greentech Media's "U.S. Solar Market Insight Report," based on a sum of "residential" and "commercial" installations and excluding "utility-scale" projects from Q1 2011 to Q1 2015 (the most recent data available).

[7] EIA

[8] EEI

[9] Henry Hub Natural Gas Spot Price - EIA

[10] Chart is depiction of the net loss rates at each of the first four year anniversaries of the original origination date of each of the respective asset backed securities highlighted (averaged across 2002 to 2012 for auto loans, 2003 to 2012 for prime residential mortgages, and 2008 to 2014 for SolarCity data). Time period for auto loans and prime residential mortgages selected to normalize for outlier effects of the financial crisis. Auto loan and prime residential data sources: A) Auto loans – average cumulative auto loan loss rates reported by Ford, Honda, Nissan, USAA, and Wachovia which are publicly reported by or on the respective companies' websites or in company issued reports; B) Residential mortgages – Wells MBS performance.

[11] Mortgage rates from bankrate.com as of May 2015.

[12] Forecast Net Cash Costs to Deploy Backlog are based on the installation costs from the most recent period ($2.13 per watt) net of the expected tax equity investment from those deployments ($1.75 per watt). We also exclude the current balance outstanding on our revolving credit facilities, which we assume to entirely have been drawn down to develop the backlog to date.

Appendix E: Definitions (1/3)

"Backlog" represents the aggregate megawatt capacity of solar energy systems not yet deployed as of the date specified pursuant to Energy Contracts and contracts for solar energy system direct sales executed as of such date.

"Customers" includes all residential, commercial and government buildings where we have installed or contracted to install a solar energy system, or performed or contracted to perform an energy efficiency evaluation or other energy efficiency services.

"Energy Contracts" includes all residential, commercial and government leases and power purchase agreements and consumer loan agreements pursuant to which consumers use or will use energy generated by a solar energy system that we have installed or contracted to install. For landlord-tenant structures in which we contract with the landlord or development company, we include each residence as an individual contract. For commercial customers with multiple locations, each location is deemed a contract if we maintain a separate contract for that location.

"Economic Value Creation" forecast represents our estimate of the 30-year net present value at a discount rate of 6% of the incremental PowerCo Project Available Cash Forecast from the MW Deployed during the applicable period under Energy Contracts. All estimates are before financing transaction costs. "PowerCo Available Cash Forecast" represents (i) Gross Project Cash Flow Forecast, less the sum of (ii) Year One Net Project Investment, (iii) Tax Equity Lease/PPA Distributions, and (iv) debt service on our Forecasted Non-Recourse Debt.

"Year One Net Project Investment" represents our estimate of the required net cash investment of the MW Deployed during the applicable period under Energy Contracts. It is based on (a) the total implied Year One upfront cost of the MW Deployed during the applicable period under Energy Contracts based on our total Cost per Watt reported in the applicable period, and is net of the sum of (b) upfront state rebates and customer prepayments, (c) total expected investment from our tax equity fund investors in the associated lease and PPA Energy Contracts based on agreements already in place, and (d) Forecasted Non-Recourse Debt.

"Gross Project Cash Flow Forecast" represents our estimate of the total project cash flows before financing forecast from the MW Deployed during the applicable period under Energy Contracts over the 30-year expected lives of the systems. This includes (a) cash payments forecast from our customers over the remaining term of such Energy Contracts, (b) estimated performance-based incentives allocated to us over the life of the Energy Contract, and (c) the associated solar renewable energy certificates [SRECs] allocated to us that have been sold under contract (typically representing 5 years of a total potential term of 15 years), and are net of (d) estimated operations and maintenance, insurance, administrative and inverter replacement costs. Operations and maintenance, insurance, and administrative costs reflect our operating expenses in our funds, or are estimated at $0.021 per watt and assumed to grow at a 2.5% inflation rate per year, and inverter replacement unit costs are estimated to decline at a (2.5%) rate per year. Energy production is estimated to degrade at 0.5% per year. For our MyPower Energy Contracts, we use the expected cash flows over the full term of the 30-year contract, and for lease and PPA Energy Contracts with terms less than 30 years, we assume the contracts are renewed at a contract price equal to 90% of the contractual price in effect at expiration of the initial term through the remainder of the expected 30-year system life.

"Tax Equity Lease/PPA Distributions" are based on the terms of the agreements we have in place with our tax equity investment partners for the MW Deployed in the applicable period under lease and PPA Energy Contracts. We do not use tax equity investment for our MyPower product. For tax equity investment in our lease and PPA Energy Contracts, our investment partners share in a portion of the Gross Project Cash Flow received over the term of the agreement. Our estimate is not inclusive of any potential buy-out of our tax equity partners' interests in the project after their minimum rate of return is achieved.

"PowerCo Unlevered Project Cash Flow" forecast represents Gross Project Cash Flow Forecast less Tax Equity Lease/PPA Distributions and is before the servicing of Forecasted Non-Recourse Debt.

"Forecasted Non-Recourse Debt" is estimated based on the forecasted terms of the long-term non-recourse debt we expect to issue collateralized by the MW Deployed during the applicable period under Energy Contracts. We forecast a 73% advance rate on the contracted Gross Project Cash Flow Forecast for our lease and PPA Energy Contracts using a 6% discount rate and a 75% advance rate on the contracted Gross Project Cash Flow Forecast for our MyPower loans using a 6% discount rate based on the terms of the current outstanding facility we use to fund that product. We further assume a 4.5% interest rate, implying principal amortization over ~20 years.

"Financing Receivables" represents our forecast of the additional non-recourse debt financing we estimate we have the capacity to issue through collateralizing our Energy Contracts available for non-recourse debt financing. For our MyPower Energy Contracts, we assume total leverage of $2.65 per watt based on our existing outstanding facility to fund this product. For our lease and PPA Energy Contracts, we assume total leverage of $1.05 per watt for (as compared to our three prior solar asset-backed loan issuances at $1.24 per watt, $1.48 per watt, and $1.71 per watt).

Appendix E: Definitions (2/3)

"Gross Retained Value" forecast represents our estimate of the 30-year net present value at a discount rate of 6% of the unlevered cash flows remaining from all of our Energy Contracts after tax equity distributions but before any additional project or other debt issued to develop and install the systems. It represents the sum of (1) "PPA/Lease Energy Contract Gross Retained Value," (2) "PPA/Lease Renewal Gross Retained Value," and (3) "MyPower Gross Retained Value."

"PPA/Lease Energy Contract Gross Retained Value" forecast represents our estimate of the net present value at a discount rate of 6% of the unlevered net cash flows forecast from all of our lease and PPA Energy Contracts (excluding MyPower consumer loan energy contracts) over the remaining contracted term. This includes for each lease and PPA Energy Contract (a) the Nominal Contracted Payments Remaining, (b) estimated performance-based incentives allocated to us over the term of the Energy Contract, and (c) the associated SRECs allocated to us that have been sold under contract (typically representing 5 years of a total potential term of 15 years), and is net of (d) amounts we are obligated to distribute to our fund investors, (e) upfront rebates, (f) depreciation, and (g) estimated operations and maintenance, insurance, administrative and inverter replacement costs. Operations and maintenance, insurance, and administrative costs reflect our operating expenses in our funds, or are estimated at $0.021 per watt and assumed to grow at a 2.5% inflation rate per year, and inverter replacement unit costs are estimated to decline at a (2.5%) rate per year. Energy production is estimated to degrade at 0.5% per year. This metric includes all lease and PPA Energy Contracts for solar energy systems deployed and in Backlog.

"PPA/Lease Renewal Gross Retained Value" forecast represents our estimate of the net present value at a discount rate of 6% of the additional customer cash payments we would receive upon renewal of all lease and PPA Energy Contracts (excluding MyPower consumer loan agreements) through a total term of 30 years at a price equal to 90% of the contractual price in effect at expiration of the initial term, escalating at the same rate per year as set in the original lease and PPA Energy Contracts, and is net of estimated operations and maintenance, insurance, administrative and inverter replacement costs. Operations and maintenance, insurance, and administrative costs and energy production degradation rates are based on the same assumptions as in PPA/Lease Energy Contract Gross Retained Value. This metric includes all lease and PPA Energy Contracts for solar energy systems deployed and in Backlog.

We assume renewal due to both (1) a longer life expectancy of the equipment used in our solar energy systems (typically 30 years or more) vs. our lease and PPA contract terms (typically 20 years) and (2) our assumption utility retail rates continue to increase at their historic pace and our expectation that the price of our energy contracts will continue to represent an economic incentive for our customers to renew their contracts.

"MyPower Gross Retained Value" forecast represents our estimate of the net present value at a discount rate of 6% the unlevered net cash flows forecast from all of our MyPower consumer loan Energy Contracts (excluding lease and PPA Energy Contracts) over the remaining contracted term. This includes for each of our MyPower consumer loan agreements (a) the Nominal Contracted Payments Remaining, (b) estimated performance-based incentives allocated to us over the life of the Energy Contract, (c) and the associated SRECs allocated to us that have been sold under contract (typically representing 5 years of a total potential term of 15 years), and is net of (d) upfront rebates, (e) depreciation, and (f) estimated operations and maintenance, insurance, administrative and inverter replacement costs. Operations and maintenance, insurance, and administrative costs and energy production degradation rates are based on the same assumptions as in PPA/Lease Gross Retained Value. This metric includes all MyPower consumer loan Energy Contracts for solar energy systems deployed and in Backlog.

"Gross Retained Value per Watt" is computed by dividing Gross Retained Value as of such date by the sum of total MWs deployed under Energy Contracts as of such date plus MWs booked under Energy Contracts as of such date but not yet deployed.

"MW" or "megawatts" represents the DC nameplate megawatt production capacity.

"MW Booked" represents the aggregate megawatt production capacity of solar energy systems pursuant to customer contracts signed (with no contingencies remaining) during the applicable period net of cancellations during the applicable period. This metric includes solar energy systems booked under Energy Contracts as well as for solar energy system direct sales.

"MW Deployed" represents the megawatt production capacity of solar energy systems that have had all required building department inspections completed during the applicable period. This metric includes solar energy systems deployed under Energy Contracts as well as for solar energy system direct sales.

Appendix E: Definitions (3/3)

"MW Installed" represents the megawatt production capacity of (a) residential solar energy systems, for which (i) all solar panels, inverters, mounting and racking hardware, and system wiring have been installed, (ii) the system inverter is connected and a successful DC string test has been completed confirming the production capacity of the system, and (iii) interconnection wiring has been completed and the system is capable of being grid connected, the latest of which is completed during the applicable period; and (b) for non-residential solar energy systems, for which (i) all solar panels, inverters, mounting and racking hardware, and system wiring have been installed, (ii) the system inverter is connected and a successful DC string test has been completed confirming the production capacity of the system, and (iii) the system is capable of being grid connected, the latest of which is completed during the applicable period. This metric includes solar energy systems deployed under Energy Contracts as well as for solar energy system direct sales. In each case in-period completion of the above criteria may be demonstrated by written verification by each of the Chief Financial Officer and the Chief Operating Officer (which may include written sub-certifications).

"Net Retained Value" forecast represents Gross Retained Value less (i) net debt outstanding as of the applicable period end and (ii) forecasted net cash costs to deploy backlog as of such date. "Net debt" represents the aggregate amounts outstanding under all non-convertible debt facilities, including all solar asset-backed loans, aggregation and MyPower facilities, Solar Bonds, other corporate debt, and our revolving credit facility as of the applicable period end, net of available cash and cash equivalents as of the applicable period end, and excludes outstanding convertible notes which we assume will be settled in equity. "Forecasted Net Cash Costs to Deploy Backlog" represents our estimate of the cash required to complete deployment of systems under Energy Contracts in backlog as of the applicable period end; it assumes the installation cost of the most recent period net of the expected tax equity investment from those deployments and no cancellations, and is net of the amount outstanding under our revolving credit facility as of the applicable period end, which we have assumed for this purpose to have been drawn down to fund initial sales costs and working capital to develop our backlog to date. This excludes incremental G&A and any potential future sales costs related to such MW.

"Nominal Contracted Payments Remaining" represents our estimate of the sum of cash payments that are customers are obligated to pay us under our Energy Contracts over the remaining term of such contracts. This metric includes Energy Contracts for solar energy systems deployed and in Backlog. As an example, if a customer is 2 years into her 20 year contract, then 18 years of contract payments remain. As an additional example, if a customer chose to pre-pay her Energy Contract, then it is included in estimated Nominal Contracted Payments Remaining only while it is in Backlog as the pre-payment has not been received. Payments for direct sales are not included.

"PowerCo Available Cash" represents the net cash flows associated solely with our Power Business, which generates a predictable long-term cash flow stream from our Energy Contracts and the underlying solar energy systems that have cumulatively been deployed through the applicable period. It excludes the net cash flows associated with our Development Business, which is dedicated to investing in and financing new solar energy systems to grow our Power Business, and thus excludes (a) installation costs, (b) sales costs, and (c) G&A costs incurred through the applicable period. PowerCo Available Cash represents our core cash flow generation assuming no additional development of new customer installations, though if PowerCo were actually to separate from DevCo it would likely retain some portion of the G&A costs. PowerCo Available Cash is calculated as (1) total cash payments from all Energy Contracts installed through the applicable period, including PBIs and SRECs less the sum of (2) operations and maintenance, insurance, administrative and inverter replacement cash costs, (3) tax equity cash distributions, and (4) interest and principal repayment debt service on all non-convertible debt including solar asset-backed loans, aggregation facilities, revolving credit facilities, and Solar Bonds.

"Undeployed Tax Equity Financing Capacity" represents a forecast of the amount of MW that can be deployed based on committed available tax equity financing for Energy Contracts.

"Unlevered IRR" represents our forecast of the internal rate of return (IRR) we expect to receive on our Unlevered Year One Investment for MW Deployed during the applicable period under Energy Contracts based on PowerCo Unlevered Project Cash Flow. "Unlevered Year One Investment" represents Year One Net Project Investment, less total expected investment from our tax equity fund investors in our lease and PPA Energy Contracts.

SolarCity
Power forever.

STATE OF NEW YORK PUBLIC SERVICE COMMISSION

CASE 14-M-0101

Proceeding on the Motion of the Commission Regarding Reforming the Energy Vision

Track I – The Distributed System Platform Provider

Track II – Regulatory and Ratemaking Issues

Comments of SolarCity Corporation

July 18, 2014

Executive Summary & Introduction

SolarCity Corporation (SolarCity) hereby submits the following comments in response to the New York Public Service Commission's (the Commission) Reforming the Energy Vision proceeding.[1] SolarCity strongly supports the policy goals of Reforming the Energy Vision (REV), and appreciates the opportunity to provide recommendations according to Track I and Track II of the proceeding, as articulated in the New York Department of Public Service (Staff) report.

SolarCity is a national leader in renewable energy services, and serves thousands of communities in 15 states, including Arizona, California, Colorado, Connecticut, Delaware, Hawaii, Maryland, Massachusetts, Nevada, New Jersey, New York, Oregon, Pennsylvania, Texas, Washington, and Washington D.C. Our customers include homeowners, businesses, government, non-profit, and others. We have thousands of customers and nearly 250 employees across New York State.

We commend the proposal's vision of how to achieve the State's policy goals in the face of rapid technological, economic, operational and environmental changes in the electricity industry. SolarCity believes the adoption of a well-designed Distribution System Platform Provider (DSPP) model would be a significant improvement over the current closed distribution model and is necessary to meet the state's policy objectives for a more efficient, clean and resilient distribution system.[2]

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[1] New York State Public Service Commission, Order Instituting Proceeding, CASE 14-M-0101, Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision, April 25, 2014.

[2] The Public Service Commission identified six policy objectives in the Order Instituting Rulemaking: (1) Enhanced Customer knowledge and tools; (2) Market animation and leverage of ratepayer contributions; (3) System wide efficiency; (4) Fuel and resource diversity; (5) System reliability and resiliency; (6) Reduction of carbon emissions.

However, SolarCity understands that Reforming the Energy Vision is about fundamentally changing the way energy is produced and delivered in New York. To that end, we believe that all options should be on the table at this point in the process. We see value in further exploring the recommendations below with stakeholders, recognizing that there will be practical barriers that slow implementation of any fundamental reform.

Several themes are present within the enclosed comments, and are outlined below. These themes reflect the public policy goals highlighted in the Staff report, and we offer these as principals that should be considered by the Commission in resulting rulings.

Enable customer choice

The essence of this proceeding is to benefit consumers, and allowing the utilities to extend their monopoly to ownership of distributed energy resources (DER) would reduce consumer choice and impede innovation in the energy sector. Expanding the monopoly service franchise agreement to DER technologies where many businesses already compete is neither prudent nor necessary for public convenience. Allowing utilities the ability to own and rate-base DER would also harm many businesses that have been growing in this space despite high barriers to entry. Instead, the Commission should seek to leverage and reduce regulatory barriers to existing competitive business models for each DER technology. Only through harnessing competition and free market forces can New York realize the ambitious goals of the REV undertaking. If realizing the goals of REV is subject to the implicit veto authority of incumbent monopolies, the admirable goals sought will never be realized. Vigilant regulatory oversight should not be preferred over inherent competitive market efficiencies.

Design a fair and competitive market

To truly reimagine the energy vision, the Commission should adopt a new construct that is at the cutting edge of thinking in the utility industry.[3] Market operations and planning functions of the DSPP should be conducted by an independent entity so as to facilitate competition. Independent system operators (ISO) and regional transmission organizations (RTO) have been successful in fostering fair and competitive electricity markets, and should serve as a model for a DSPP structure wherever possible, adjusting the model appropriately to account for differences between transmission and distribution. Utilities should continue to manage physical operations and asset management functions while in close coordination with an independent DSPP.

Establish market certainty and transparency

Adoption of DER can only grow when policies and compensation mechanisms are designed with certainty and transparency. Any compensation for DER should fully capture the system and environmental benefits offered by DER technologies and should be simple in nature for all parties involved including consumers, DER providers and investors. The most efficient way to do this is to maintain and improve current net energy metering (NEM) and interconnection policies, and to develop markets that enable such systems to provide ancillary services to the bulk power market. To date, no study has transparently proven that the costs of NEM outweighs its benefits in New York while taking into account the various system, environmental, and societal benefits of the technology that net metering applies to. Net metering is fully consistent

[3] Imagining a new construct – an independent system operator for the distribution network; Farrokh Rahimi and Sasan Mokhtari; Fortnightly Magazine - June 2014

with the Commission's vision, as it is easy to administer and sends appropriate price signals to customers. Continuation of NEM is not at odds with fundamental cost-causation tenants of efficient rate design. Rather, NEM is consumer friendly, relied upon by the financial community and facilitates "cost causers to be cost bearers" through complimentary rate design constructs that foster transparency and efficiency. If NEM cost shifts become manifest through empirical, evidentiary based determinations, then changes to rate design are the appropriate regulatory response – not full-retail-credit NEM dismantling.

Allow seamless integration of DER into the grid

While we do not support ownership of DER by the distribution utility, new mechanisms that incent distribution utilities to facilitate deployment of DER while enabling consumer choice should be considered so as to enable utilities to benefit from the increased penetration of DER. Utilities should no longer be reactive to DER adoption, and should incorporate necessary upgrades into distribution planning to reduce the need for investment in central power generation and traditional transmission and distribution projects. Standby charges are a major example of inefficient barriers to DER technologies, and exemptions for these charges should be extended broadly and beyond the current 2015 expiration.

SolarCity looks forward to further engaging in the REV proceeding, and offers specific comments to a subset of the questions posed by the Commission's rulings.[4] Comments herein are corresponding to the questions as organized in the rulings.

[4] PSC "Ruling Posing Questions on Selected Policy Issues and Potential Outcomes, Establishing Comment Process, and Revising Schedule", June 4, 2014; PSC "Ruling Issuing Track 2 Questions and Establishing A Response Schedule", May 1, 2014

Track I – The Distribution System Platform Provider

Question II - Optimal Ownership Structures for DERs
Comment on the potential approaches to utility engagement in DER to ensure a robust DER market.

As Staff highlights, the Commission's Vertical Market Power Policy[5] establishes that utility ownership of wholesale generation introduces market power concerns, which have been deemed unacceptable at the transmission level. As such, SolarCity is strongly opposed to utility-owned DER with the utility also serving key DSPP functions, and believes that such a model introduces significant conflicts of interest that would impede growth and innovation in the DER market. None of the competitive electricity markets in the U.S. permits utilities to own generation and/or transmission assets, and also serve as the wholesale market and system operators.[6]

Furthermore, even with a market structure in which the utility owns the distribution system but does not conduct key market facilitation functions of a DSPP, utility ownership of DER would introduce conflicts of interest and asymmetric information advantages that could harm the development of distributed products and services. Consumers currently have choice of DER suppliers in a competitive market, which provides them with the most benefits and allows for market growth and innovation. Examples of unfair utility advantages include:

- The distribution system owner has advance knowledge of where opportunities exist for DER through its understanding of locations with spare capacity on the system. These areas may be least likely to have interconnection challenges or provide the greatest avoided cost opportunity. Non-disclosure of this information would afford the utility an advantage over third-party DER providers.
- The utility has detailed historical customer usage information that can greatly facilitate customer acquisition. This would create an unfair playing field for third-party DER owners trying to compete in customer acquisition against utilities.
- As the physical operator and coordinator of the distribution system, the utility may be incented to utilize its own DER resources for reliability-driven events, to increase compensation to those resources.

Based on these limited examples alone, granting distribution utilities the right to own DER could result in competitive advantages and potential unfair market power for the utilities, which could distort the playing field and market clearing prices for certain products and services provided by DERs.

Rather than creating incentives that encourage utilities to leverage their asymmetric access to information, efforts should be specifically undertaken to empower customers and other

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[5] "In creating a competitive electric market, the Commission has viewed divestiture as a key means of achieving an environment where the incentives to abuse market power are minimized. Recognizing that vigilant regulatory oversight cannot timely identify and remedy all abuses, it is preferable to properly align incentives in the first instance." Case 96-E-0900, Statement of Policy Regarding Vertical Market Power

[6] It may be argued that the limited market authorized by FERC for the area served by Southern Company affiliates is an exception. But few consider this area to be a competitive electric market.

independent providers of DER to effectively utilize this information to build and be compensated for deploying resources where they provide the greatest value to the system. It is important to note that whether or not a utility took advantage of asymmetric information or market power, any perception of an uneven playing field would likely constrain investment and participation by investors, third-parties and customers, which would hinder the development of DER.

Any scenario in which the utility serves as the DER-owner impedes technological innovation, customer choice and fair competition. This configuration offers unfair terms with incumbent advantages and expands the monopoly service franchise agreement in ways that are neither prudent nor necessary for public convenience. Aggregating more power through intentional policy design for the benefit of incumbents is not a new vision, rather edification of the old vision. Allowing utilities the ability to rate-base DER investments offers regulated utilities an unfair advantage and eliminates consumers' choice in DER providers. Many companies that are unable to rate-base have established business models to provide DER in this space, and allowing a regulated utility to move into this space would be detrimental to an existing market based on competition and consumer choice.

SolarCity embraces a future where the greatest number of entities is incented to deploy and facilitate a clean, distributed and resilient distribution system. Market design that fosters fair and robust competition should be the corner stone of this undertaking; it should not be an aspiration that is wholly dependent on efficient regulatory oversight of incumbent behavior. We strongly support the development of mechanisms to fairly incent utilities to do so as well, including direct financial incentives for facilitating the deployment of DER. Under Track II of the REV proceeding, new incentive structures could be developed that incent the utilities to directly engage in DER deployment in ways that encourage increased penetration of DER, yet do not create the potential for market power or systemic competitive advantages.

Whether or not a utility is permitted to own DER, a DSPP that controls the key market facilitation and system operations functions should be prohibited from having ownership interests in DER connected to the distribution system.[7] Stakeholder forums across the country have established that dual ownership of generation and transmission assets paired with wholesale market and system administration is inefficient;[8] Standards of Conduct[9] alone did not sufficiently address conflicts of interest to promote competitive markets and the optimal outcomes for customers. The need to separate ownership and the function of facilitating competitive markets and operating the grid system has been one of the key rationales for the creation of ISOs and RTOs over the last twenty years, which should not be ignored in this proceeding.

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[7] Competitive DER providers should not be precluded from self-supplying functions attributed to the DSPP.

[8] FERC Order 2000 encouraged transmission owners to voluntarily form RTOs with minimum characteristics, including independence, but deferred to the jurisdictional utilities and their respective stakeholder initiatives in design details. These stakeholder discussions resulted in the creation of seven RTO/ISOs in the U.S. as of 2014 representing the majority of U.S. electricity consumers.

[9] "FERC's Standard of Conduct for Transmission Providers include three primary rules: (1) The 'independent functioning rule,' that requires transmission function and marketing function employees to operate independently of each other; (2) The 'no-conduit rule' that prohibits passing transmission function information to marketing function employees; and (3) the 'transparency rule,' that imposes posting requirements to help detect any instances of undue preference."

Question III: DSPP Identity
Comment on whether incumbent utilities, or an independent entity, should serve as the DSPP.

The Staff report articulates five categories of functions the DSPP would be responsible for performing, including (1) DSPP planning, (2) markets, (3) energy efficiency, (4) advanced distribution management systems and (5) communications. SolarCity believes the Commission should explore unbundling these functions and allowing different entities to perform different functions, leveraging the existing model for the transmission system and wholesale markets in competitive markets where appropriate.

SolarCity also recommends adjusting the definition and organization of some of the DSPP functions as outlined by Staff in order to drive increased clarity on the intended responsibility of the DSPP. In particular, we recommend disaggregating Staff's "Advanced Distribution Management Systems" function into two distinct functions: "System Operations" and "Physical Operations" of the grid. This distinction is drawn so as to reflect how operational responsibilities are typically divided on the transmission grid, which we find useful as a guide in the distribution grid as well. Each of these groups of functions, both DSPP- and SolarCity-recommended, is discussed in order and Table 1 summarizes our recommendations regarding the type of entities that should perform each function.

Table 1. Proposed DSPP Functions by Responsible Entity

DSPP Functions – Staff Report	Functional Summary	Responsible Entity			DSPP Functions – SolarCity Recommendation
		Independent Transmission Model Corollary	Staff Report	SolarCity Recommendation	
(1) DSPP Planning	Plan and design a safe and reliable distribution system in a manner that integrates DER as primary means of meeting system needs.	Independent Entity (ISO/RTO/ PUC/PSC)	Distribution Utility	Independent Entity	(1) Distribution Planning
(2) Market Facilitation	*Products*/Services: Identify and define products/services to be exchanged between DSPP and participants	Independent Entity (ISO/RTO)	Distribution Utility	Independent Entity	(2) Market Facilitation
	Pricing: Develop pricing structures for products/services (market-based, tariff-based, contractual)				
	Scheduling and Settlement: Integrate resources plans, coordinate energy schedules, and administer and verify settlements				
(3) Energy Efficiency	Integrate energy efficiency into system planning and operations	N/a	Distribution Utility	Independent Entity	Move into Planning/Markets
(4) Advanced Distribution Management Systems	*Power Systems Operations:* Direct the operation and coordination of power flows to satisfy system needs and imbalance variations, including supply and demand; operate system to ensure economical, reliable and stable delivery of electric power	Independent Entity (ISO/RTO)	Distribution Utility	Independent Entity	(3) System Operations
	Physical Operation: Coordination and operation of equipment in the field, including unplanned outage response, emergency response, circuit reconfiguration, equipment setting adjustments, routine clearances, etc	Transmission Utility	Distribution Utility	Distribution Utility	Physical Operations***
	Asset Management: Managing their asset life cycle to meet the desired level of reliability at the lowest total cost of ownership possible	Transmission Utility	Distribution Utility	Distribution Utility	Asset Management***

(5) Communications	Acquire, install and operate communications networks capable of supporting a smart grid	Transmission Utility	Distribution Utility	Distribution Utility	Move into Asset Management***

*An independent entity is an entity without an ownership interest in infrastructure or energy resources, preferably a not-for-profit organization.
**All entities, whether independent or utility, should be subject to strong Commission oversight.
***Denotes a function that should be attributed to distribution utilities, not the DSPP.

STAFF REPORT FUNCTION 1: DSPP PLANNING

<u>Summary of function described in Staff report</u>

Staff describes the responsibility of the planning function as designing a reliable, resilient and safe distribution system in a manner that integrates DER as a primary means of meeting system needs. This will require developing a planning framework that considers the broadest range of options to meet forecasted needs, including distribution investments and distributed energy resources side-by-side. A key part of Staff's planning function is to "plan for and accommodate customer-sited generation and demand response resources."

<u>SolarCity recommendations on DSPP planning function</u>

Adapt the independent system operator model as the starting point for the design of the DSPP structure.

In New York, the NYISO facilitates a multi-stakeholder transmission planning process, working in coordination with the transmission owners.[10] NYISO conducts the Reliability Needs Assessment (RNA), which identifies long-term reliability needs, and solicits competitive solutions across all resource types, including generation, transmission and demand-side management. The Commission reviews proposals for new electric transmission lines and upgrades to existing facilities. This approach promotes transparency and competitiveness, and ensures that independent organizations with customer-aligned incentives are responsible for capital investment approvals that will impact the development of New York's resource profile for decades.

SolarCity believes a similar multi-stakeholder structure should be adopted for the distribution system planning function, whereby an independent entity consults and coordinates with all distribution system stakeholders, including the distribution utilities, to conduct distribution planning studies for future needs and ultimately acts upon those plans by approving solutions that are consistent with the public policy objectives. This independent entity should be responsible for conducting scenario-based analyses, which would consider multiple resource portfolios including deploying DER as non-wires alternatives, to meet distribution system reliability needs. The independent entity would also ensure that the distribution planning process proactively plans the distribution system for seamless integration of DER investments.

Empowering an independent party, which is fully aligned with achieving REV's goals, to oversee this planning function within the oversight of the Commission promotes transparency and ensures that long-term distribution system investments are forward-thinking and executed fairly and competitively. Introducing greater transparency and competition into the distribution

[10] Transmission Expansion in New York State; New York Independent System Operator, November 2008 http://www.esai.com/power/09/pdfs/NYISO_Transmission_WhitePaper_1108.pdf

planning process will drive down total system costs due to competition across DERs and distribution investments to meet forecasted needs.

As an initial step, open the provision of identified DSPP planning needs to third-parties.

SolarCity recognizes that distribution planning is different from transmission planning in that intimate, local knowledge of the distribution system is required for effective and efficient distribution planning. These differences may pose a practical challenge to immediately adopting a fully independent, multi-stakeholder planning model.

However, as an initial step, whether independently- or utility-administered, the process for meeting forecasted distribution system needs should be made more competitive and transparent. To be clear, these forecasted distribution system needs could be driven by a variety of factors, including load growth, distributed generation penetration, or aging infrastructure. Under a model that allows for competition, third-parties would be able to offer DER bids that defer forecasted distribution investments. For example, after identifying high value distribution projects through a multi-stakeholder process, projects above, for example, a minimum capacity or nominal monetary value threshold could be identified for competitive solicitation. Such projects are likely to be large distribution capacity upgrades such as substation upgrades.

Adopting a more competitive model for planning distribution infrastructure would be consistent with an increasing trend towards competition at the transmission and distribution level. At the distribution level, as Staff is aware, Con Edison is currently seeking proposals for 52 megawatts of DERs that would delay the need to build a $1 billion substation.[11] In California, Southern California Edison is currently administering a request for information for distributed energy resources that can provide alternatives to SCE's distribution system upgrades necessary to accommodate forecasted load growth in the Rancho Cucamonga area.[12] In this framework, distributed energy resources capable of reducing load during peak conditions could be considered a viable option to defer significant distribution investments such as substation upgrades. At the transmission level, most recently, FERC Order 1000 eliminated the incumbent transmission owners' federal right-of-first-refusal for certain large, economic transmission projects, which is expected to increase third-party competition for bids on those types of transmission projects.

As the range of solutions capable of fulfilling distribution system needs expands to include both wires and non-wires solutions, consumers will benefit from these planning structures that encourage broad competition. If designed properly, a competitive, multi-stakeholder distribution planning process would allow diverse types of DERs to compete for large distribution investment deferrals, while meeting the required levels of security and reliability.

SolarCity advocates that utilities should continue their mandate to own and physically operate distribution infrastructure assets, but allowing third parties to offer competitive DER bids to

[11] Naureen S. Malik and Jonathan N. Crawford; "Con Edison Seeks to Avoid Building $1 Billion Substation"; Bloomberg News, June 28, 2014; http://www.bloomberg.com/news/2014-06-27/con-edison-seeks-to-avoid-building-1-billion-substation.html
[12] See SCE's Alternative Distribution Generation Solutions RFI on sce.com

fulfill large capacity-related needs will naturally drive innovation and ensure the most cost-effective solutions are employed. Furthermore, while security concerns over access to utility distribution and planning data may appear to be a roadblock to third-party participation in planning, current successful efforts to encourage third-party engagement in siting of distributed energy resources show that utility distribution planning and asset data can be shared with qualified parties at low risk.[13] SolarCity believes replicating where appropriate the existing multi-stakeholder transmission planning process for distribution planning would be an incremental and achievable step, as it would leverage an existing process to which the utilities are familiar.

STAFF REPORT FUNCTION 2: MARKET FACILITATION

Summary of function described in Staff report
Staff outlines three categories of activities under the markets function, including: (1) evaluating net-benefits of DERs and understanding how these potential benefits and costs accrue to different participants; (2) identifying and defining the appropriate products and services for distribution-level transactions; and (3) developing pricing structures for new products and services. To be clear, pricing structures could be market-based, tariff-based, or contractual.

SolarCity recommendations

Require that the market facilitation function be performed by an independent entity to ensure fair and equitable distribution-level outcomes that benefit consumers and achieve stated policy goals.

An independent entity performing market facilitation functions would allow for a truly competitive and innovative DER market. This structure eliminates the economic incentive of the distribution market operator to act in a way that benefits its assets by favoring or disfavoring any participant, and allows for the execution of public policy that might otherwise be misaligned with the interests of a utility. SolarCity is in strong favor of such an independent operator to facilitate the DSPP market function. In an increasingly competitive distribution world, it is only with an independent entity that the incentives of the market facilitator will fully align with the customer and the public good.

This independent entity would be responsible for leading the cost-benefit analysis of DER, identifying and defining distribution-level products and services, developing compensation structures for these products and services, which could include market-based, tariff-based, or contractual pricing for products and services, and managing scheduling and settlements. However, the decision-making process for this independent entity should be accessible and transparent. Clear rules and requirement around stakeholder engagement, with a mandated process for consideration and decision-making that features robust stakeholder engagement would be imperative.

Leverage the independent transmissions market operator model in designing the DSPP structure wherever possible.

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[13] California IOU Renewable Auction Mechanism (RAM) Maps with distribution asset and planning data: http://www.cpuc.ca.gov/PUC/energy/Renewables/hot/Renewable+Auction+Mechanism.htm

The independent transmissions market operator model being utilized to serve two-thirds of the electricity consumers in the U.S.[14] clearly separates the ownership of the assets from the administration of the wholesale market. In New York, the establishment of the NYISO was effective in increasing competition and broadly delivering benefits to consumers that exceed the costs of establishing an independent market operator,[15] and SolarCity believes similar benefits could be reaped as New York modernizes its distribution system. Recognizing that differences exist between distribution and transmission systems, the DSPP model should mimic the intent and structure of regions with independently administered wholesale markets wherever possible, striving for an independently-coordinated distribution system market that does not unnecessarily overburden utilities and market participants. The value of this independent model would be retained whether the pricing structures developed by the market facilitator are market-based, tariff-based, or contractual.

DER owners should be able to access wholesale markets without utility involvement.

The Staff report discusses a potential role of utilities in providing the interface between DER and NYISO wholesale markets. While providing access to DER in itself is a potential value-added service for utilities, SolarCity believes that DER owners should not be mandated to go through utilities for access to wholesale markets. Market facilitation is a service suitable for significant technological and customer service innovation, and limiting provision of that service to only utilities reduces competition and increases costs for customers.[16]

STAFF REPORT FUNCTION 3: ENERGY EFFICIENCY

Summary of function described in Staff report

Staff described this function as consisting of comprehensive integration of energy efficiency programs into distribution-level planning. Rather than the administration of static energy efficiency programs funded through surcharges, the administrator would consider energy efficiency as a distributed energy resource and consider it a DER in distribution planning.

SolarCity recommendations

An independent Distributed Planner should be responsible for integrating energy efficiency resources into distribution system planning.

SolarCity views the comprehensive integration of energy efficiency programs into distribution-level planning as intimately related to Function 1: Distribution Planning. Therefore, the

[14] ISO RTO Council (IRC): www.isorto.org/about/default

[15] "We conclude that significant benefits have resulted from the impacts of NYISO operators and the market incentive effects we studied. The system-wide benefits exceed the NYISO budget costs in every year from 2000 through 2006. In the later years the difference is hundreds of millions of dollars, or roughly 5% of system-wide production and fixed O&M costs." A Cost-Benefit Analysis of the New York Independent System Operator: The Initial Years; Susan Tierney, Edward Kahn, Analysis Group, March 2007

[16] Similarly, development of various "enhanced services" discussed in section VI of the Track I Policy questions are suitable for the competitive market and utility participation in those services need to be governed by appropriate rates and regulations to ensure fair, robust competition.

independent entity administering Distribution System Planning should consider energy efficiency as a resource alongside all DERs and distribution infrastructure investments when planning to meet future system needs.

An independent entity should be responsible for implementing and administering approved energy efficiency resources.

After an energy efficiency program is approved through the Distribution Planning process, SolarCity recommends that the implementation, marketing and administration of energy efficiency programs should be conducted by a separate, customer-facing independent entity or entities with core competencies in customer acquisition, retention and program administration. This independent entity would be charged specifically with driving adoption of energy efficiency solutions that are approved through the distribution planning process.

STAFF REPORT FUNCTION 4: ADVANCED DISTRIBUTION MANAGEMENT SYSTEMS

<u>Summary of function described in Staff report</u>
Staff described this function as consisting of the physical coordination and operation of the distribution system and control of distributed energy resources on the distribution system, performing the operational duties of distribution-level balancing, dispatching, interfacing with the transmission-level balancing authority, and physical operation of distribution assets.

<u>SolarCity recommendations</u>

An independent entity should manage system operations responsibilities.

The responsibility for system operation and coordination of power flows on the grid should reside with an independent entity. This approach is again analogous to the operation of the bulk transmission system at the ISO level in all organized wholesale markets, where dispatch and day-to-day system operations are the purview of the independent system operator.

FERC Order 888 and 889[17] established the foundation of non-discriminatory open access transmission services by requiring utilities to functionally unbundle transmission and generation services. However, unbundling of transmission and generation only attempted to reduce the ability of utilities to exploit dual ownership, but did not change the incentives of utilities to use transmission assets to favor generation.

For these reasons, FERC Order 2000 encouraged utilities to voluntarily form regional transmission operators. FERC concluded through a national stakeholder process that the lack of independent operation of the bulk power system enabled the continued ability of transmission owners to discriminate in the operation of their systems to favor their own affiliates and further

[17] FERC Order 888 required utilities that own, control or operate transmission to develop open access transmission tariffs and non-discriminatory service. FERC Order 889 established Standards of Conduct that required utilities to functionally separate transmission and wholesale power merchant functions.

their own interests.[18] Even if discrimination were detectable, regulators realized a system that attempts to control behavior motivated by economic self-interest through the use of Standards of Conduct alone would require constant and extensive policing and granular oversight. This level of oversight comes at a cost, both to the regulator and the utility, which is ultimately borne by the customer. Given the lessons of restructuring from FERC Order 888, 889 and 2000, it would be far more effective to correctly align incentives of the DSPP from the start by requiring independent entities to perform key functions of system operation related to DERs.

The independent entity operates the system as needed to ensure the reliable and safe delivery of energy. The system operator relies on available resources to ensure grid stability and delivery, utilizing available third-party assets or services as needed, including customer owned DER. When dispatching third-party assets or services, the system operator can rely on all available resources, the availability of which would be dictated by existing contracts, tariffs or market mechanisms. In supporting system operation, the distribution utility is responsible only for physical delivery of the product via its grid assets. This approach mimics the ISO model, in which an independent entity utilizes system operational control over key grid assets.[19]

By leveraging an independent entity to manage real and reactive power flows on the distribution system in compliance with requirements set by the Commission and existing relationships with the ISO, transparency and an open and non-discriminatory process can be ensured without influence from the owner of the distribution assets. Such transparent operation will increasingly become important as consumers with DER assets look to increasingly engage in transactive energy opportunities in real time.

While distribution utilities would not be given control over system operations of the distribution system, they would retain full responsibility for physical operation of equipment and maintenance of the grid. With their intimate knowledge of the distribution infrastructure, distribution utilities would retain responsibility for coordination and operation of equipment in the field, response to unplanned outages, management of emergency response efforts, execution of circuit reconfiguration, optimization of equipment settings adjustments, administration of routine system clearances, and management of other physical operations actions. In fulfilling these physical operations responsibilities, the distribution utility also plays a central role in ensuring reliable delivery of energy to customers. As such, practical demarcations of operations responsibilities between the system operator and physical operator must be clearly defined so as to ensure safe, reliable and efficient coordination.

Furthermore, distribution utilities should also be allowed and incented to serve an enhanced role in serving the grid of the future through investment, maintenance and upkeep of the grid. Enabling utilization of third-party DER to deliver advanced and value added services to customers provides enhanced opportunities for utilities, DER owners and grid customers.

[18] "...we do conclude that opportunities for undue discrimination continue to exist that may not be remedied adequately by functional unbundling." FERC Order 2000, page 65

[19] Section 2.2.24 NYISO Transmission Dispatch http://www.nyiso.com/public/webdocs/markets_operations/documents/Manuals_and_Guides/Manuals/Operations/trans_disp.pdf

STAFF REPORT FUNCTION 5: COMMUNICATIONS

Summary of function described in Staff report

Staff described this function as including the identification and adoption of intelligent communication networks that can support SCADA, telemetry, distribution automation and data backhaul. These networks should be capable of providing situational intelligence to the transmission operator involving forecasting, loads, DER activity, and real and reactive power flows from the distribution system to the T-D interfaces.

SolarCity recommendations

The utility should continue to be responsible for modernizing and integrating the distribution system's communication infrastructure.

SolarCity agrees with Staff that the distribution utility, as owner of the distribution system, is the appropriate entity to lead the development of communications systems and to oversee the modernization of distribution communications infrastructure. A critical component of a modern communications infrastructure will be the adoption of a "bring-your-own communications" policy, which would require utilities to integrate third-party owned communications infrastructure into its operations. Utilities can dramatically extend their situational intelligence by consuming data from third-party and customer-owned communications infrastructure, with drastic savings over a dedicated utility communications infrastructure. For example, rather than requiring DER customers to install utility-specified communications equipment in order to transmit data with the utility, customers should be able to share data with utilities through their existing infrastructure. By leveraging existing customer broadband and other networks, data can be shared without additional infrastructure costs. This approach enables DER owners and third-parties to contribute to the development of the communications infrastructure, leveraging modern technologies like broadband to more rapidly and cost-effectively connect and integrate DER.

SolarCity also suggests that the Communications function is a subset of the distribution utility's larger function of Asset Management and Physical Operation of the grid, and should not be characterized as a standalone DSPP function itself.

Question IV – Benefits and Costs

Discuss the preferred analytical framework to assessing benefits and costs, with particular attention to the different ways that benefits and costs may need to be considered in various stages of this initiative, and the methodologies and tools that may be appropriate to each.

To date, no analysis of the full costs and benefits of net metering has proven either that this policy, or the technologies it applies to, causes additional costs to ratepayers in New York. Several studies have, in fact, shown that the benefits of net metering actually meet or exceed the costs, and have been done so with various methodologies.[20,21,22,23,24] As the Commission is

[20] Energy & Environmental Economics, *Nevada Net Metering Impact Evaluation,* Prepared for the State of Nevada Public Utilities Commission, July 2014, page 7, http://pucweb1.state.nv.us/PDF/AxImages/DOCKETS_2010_THRU_PRESENT/2013-7/39428.pdf

aware, NYSERDA has been ordered to assess the benefits and costs of net metering policy.[25] We urge the Commission and NYSERDA to conduct this study in a fair and transparent method, and until such a study is conducted, the Commission should not predetermine net metering as inefficient with need for revision or elimination.

[21] Vermont Public Service Department, *Evaluation of Net Metering in Vermont Conducted Pursuant to Act 125 of 2012,* January 2013, page 31, available at http://publicservice.vermont.gov/sites/psd/files/Topics/Renewable_Energy/Net_Metering/Act%20125%20Study%20201301 15%20Final.pdf

[22] Thomas Beach, Patrick McGuire, Crossborder Energy, *The Benefits and Costs of Solar Generation for Electric Ratepayers in North Carolina,* October 18, 2013.

[23] "Evaluating the Benefits and Costs of Net Energy Metering in California," January 2013, Crossborder Energy. Available at http://votesolar.org/wpcontent/ uploads/2013/07/Crossborder-Energy-CA-Net-Metering-Cost-Benefit-Jan-2013-final.pdf

[24] "The Benefits and Costs of Solar Distributed Generation for Arizona Public Service," Crossborder Energy (May 8, 2013); Available at http://www.seia.org/sites/default/files/resources/AZ-Distributed-Generation.pdf

[25] Case 03-E-0188 - Proceeding on Motion of the Commission Regarding a Retail Renewable Portfolio Standard. Order Authorizing Funding and Implementation of the Solar Photovoltaic MW Block Programs (Issued April 24, 2014).

Track II – Regulatory and Ratemaking Issues

Section I - Outcomes-Based Ratemaking

2) New outcomes/metrics

- b. *What specific outcomes of REV should be incentivized? What percentage of utilities potential earnings or how many basis points of earnings should be tied to these incentives at standard and superior performance levels?*

Utilities should be incentivized to facilitate broad market adoption of DER resources (a pre-requisite to a successful REV) and to pursue distribution plans that exploit the capabilities of deployed DER, even if those plans involve less utility-owned investments. The specific basis points adjustments should be determined in more detailed implementation proceedings. The incentives could be a mix of 1) reduced returns for conventional investments and planning processes that make DER market attributes redundant,[26] 2) mechanisms to preserve return indifference for pursuing non-owned alternatives, and 3) enhanced returns for pursuing non-conventional alternatives that optimize DER value. In early stages of implementation, incentives should be more weighted towards achievement of broad end-user deployment targets and pursuit of pilot activities. Over time, incentives would become more targeted towards overcoming key market deployment gaps that utilities can facilitate and getting more grid services value from deployed DER.

- g. *What utility incentives are necessary to promote comprehensive integrated resource planning at the distribution level that would consider all DER alternatives to satisfy system expansion, system replacement, and / or to meet clean energy goals? Are there examples for multi-year performance metrics which would be superior in providing value to customers compared with an annual metric?*

Utilities should be required to both plan for the seamless integration of DER throughout their distribution infrastructures, and consider the implementation of DER first over more traditional capital upgrades. Con Edison's proposal for 52 megawatts of DERs would delay the need to build a new substation in an amount over $1 billion.[27] In addition, this proposal, which recognizes the value of DER as an alternative to traditional utility capital upgrades, only weighs system benefits. This model should be expanded throughout New York with additional consideration of environmental benefits and other public policy goals of the Commission.

7) Utility as DSPP and as DER-owner: neutralizing incentives

- a. *Can ratemaking or structural mechanisms be established to remove the utility bias in favor of DER investments owned by the utility or its affiliates?*

Any scenario in which the utility serves as both the DSPP and DER-owner impedes technological innovation, customer choice and fair competition. This configuration offers unfair

[26] One example would be differential asset returns if the utility were to transfer the operations and planning of its assets to an independent operator.

[27] http://www.bloomberg.com/news/2014-06-27/con-edison-seeks-to-avoid-building-1-billion-substation.html

terms with incumbency advantages and improperly expands the monopoly service franchise agreement in ways that are neither prudent nor necessary for public convenience. As such no ratemaking and structural mechanisms are sufficient to allow for ownership of DER at the utility level. Participation at the unregulated affiliate level should be allowed, subject to standard PSC restrictions to prevent a biased market that may thwart competitive entry. However, allowing only utilities and their affiliates to invest in DER with the risk mitigation and cross-subsidization opportunities (actual or implied) that their regulatory status presents is a grossly unfair advantage that would damage a growing market of DER providers.

b. *If the utility owns DER investments, is it better if they are rate based and rate regulated, or owned by unregulated affiliates? Is there another option? Does this provide utility incentives to misallocate costs between regulated and unregulated products?*

The status-quo of allowing non-regulated affiliates of a utility competing for DER development promotes fair competition in the market. However, the ability to rate-base DER investments offers regulated utilities an unfair advantage and costs customers and the market open choice. Many companies that are unable to rate-base have established business models to provide DER in this space, and allowing a regulated utility to move into this space would be detrimental to an existing market based on competition and consumer choice.

Section III – Rate Design

1) How do the customer incentives and disincentives under current rate design affect DER participation?

Current rate design offers several incentives and disincentives that depend on the type of DER. Volumetric pricing with time-differentiated or tiered structures provide incentives for customers to engage in load-reducing DER. The more a customer's bill is calibrated to actual usage of electricity and any market signals that exist, the more control the customer ultimately has over his or her bill -- and the greater motivation the customer will have to modify electricity consumption. Conversely, rates that rely more heavily on fixed charges offer weaker financial motivation to invest in DER. Additionally, options such as net metering have greatly enhanced qualifying DG customers' willingness to invest whereas, in contrast standby charges have acted as a major disincentive for non-exempt DG such as CHP.

2) Tariffs for DSPP products

a. *How should non-monetized benefits and costs (e.g., carbon) be accounted for in rates, if at all?*

Non-monetized benefits and costs should be accounted for in rates through a transparent and simple mechanism that rewards customers for "good behavior." Net metering coupled with good rate design reasonably accounts for non-monetized benefits such as greenhouse gas and criteria pollutant emissions reduction, peak load reduction and shifting (in the case of PV), and energy supply diversification. This mechanism is transparent, equitable among consumers, is relatively easy for customers to understand, and provides DER providers and their investors with market certainty. In a recent study conducted by the Vermont Public Service Department, the societal benefits of net metering a single PV system are roughly equal to the costs to ratepayers when taking into account the value of reduced greenhouse gas emissions, avoided energy and capacity costs, avoided regional transmission costs, deferment of transmission and distribution capital investments, market price suppression, and others.[28]

b. *Which non-monetized benefits should be accounted for, if any?*

Different DER technologies offer different benefits that could be monetized. Certainly, environmental benefits should be monetized, including avoided greenhouse gas and criteria pollutant emissions. System benefits that should be accounted for include peak load reduction, controllability by the DSPP, voltage support and other ancillary services, avoided energy and capacity costs, avoided regional transmission costs, deferment of transmission and distribution capital investments, electricity market price suppression, and energy supply diversity.

3) For each of the products and services to be ***procured*** *by the DSPP, how should the pricing be determined? (If the answers differ by product, please specify to the extent possible)*

a. *Should pricing be based on embedded cost of service?*

Pricing of different products offered by DER technologies should not solely be based on the embedded cost of service. This approach would not fully monetize all system, environment, market, and other societal benefits. Further, this mechanism would likely favor certain types of DER technologies over others, and would not offer any market development benefits needed by some technologies.

b. *Should pricing be determined through a market mechanism which might reflect locational based marginal pricing?*

We urge the Commission when developing pricing for different DER benefits, that the locational based pricing offered to consumers would be based on distribution system status and their location within a system in which they have had no engineering contribution to, and would thus reduce or manipulate their choice in which DER technology to invest in. The price for energy should not be based on location, and DER technologies that reduce customer load paired with net metering benefits should be equitable across all customers. Pricing of additional DER benefits such as frequency or voltage regulation are inherently locational based and thus, such a mechanism would be beneficial to the system.

c. *Should pricing be determined via request for proposals and individually negotiated contracts? Should individually negotiated contracts be made available for public inspection?*

Pricing for DER benefits should be stable, transparent, and open to subscription. Lessons learned from earlier versions of the NY-Sun and main tier solicitations have shown that competitive processes have resulted in artificial bids and have been administratively burdensome. DER providers would not fully enter into contracts with property owners or design a system until after

[28] http://www.leg.state.vt.us/reports/2013ExternalReports/285580.pdf

winning a solicitation, and thus not know the actual cost of deployment to design a full bid. Also, in the time it would take to administer a full solicitation, a property owner under a non-binding agreement may execute their right to exit that agreement, further delaying deployment.

e. *Should the pricing vary by time and / or geographic location?*

Any pricing that varies by time and/or location should only be done transparently, and should continue to offer market certainty to consumers and DER providers. Any pricing that varies with too much granularity would place a burden on the consumer and DER providers, reduce their visibility and certainty into the market, and limit market growth.

f. *Should the pricing be differentiated for products related to reliability, economics, or public policy?*

Pricing of DER benefits should be differentiated for products related to a combination of all three factors: reliability, economics, and public policy. The right mix of these three factors would offer system benefits, environmental benefits, consumer choice, and market development for more nascent technologies.

5) New rate designs

c. *Should rates for products or services procured to achieve certain incentives, like more efficient utilization of the distribution system through peak load reductions, be set by the Commission or allowed to be set by the utility companies as necessary?*

Rates for products and services procured to achieve certain objectives should be set by the Commission or another independent entity, and the utility should not be allowed to set these rates unilaterally. The utility incentives may not fully align with the goals of the Commission in this proceeding, including improved customer choice, environmental benefits and market development. Further, the utility will continue to exist as a regulated monopoly, thus the Commission should still have authority in all ratemaking actions.

d. *Should the current volumetric rate designs used to recover embedded costs be revised to move toward fixed pricing? What are the tradeoffs or unintended consequences of moving towards fixed pricing that should be considered?*

Moving away from volumetric pricing completely changes the economics for many DER resources, which primarily respond to utility pricing. Fixed pricing runs counter to the objectives of REV, which seeks to promote customer investment in DER and active participation in the distributed services platform. Recovery of embedded, sunk costs does not have to be done in a fixed manner; cost allocation can be done in a way that incents desired outcomes while still ensuring fair recovery. A fixed charge is similar to the existing standby charges, which many DER providers cite as a major challenge to market growth, and could face many of the same issues in design. Also, as stated by Staff, fixed charges could send a perverted price signal in terms of reducing grid demand, either through energy efficiency or other distributed generation investments.

g. *What payment structure would facilitate distribution utility ownership of DER behind customers' meters? For example, should a customer be provided with a direct payment for allowing the utility to locate the DER on its property or should the customer be allocated a portion of the ongoing DER benefit?*

Utilities should not be able to own and rate base DER in front of or behind customers' meters. Allowing utilities the ability to rate-base DER investments offers regulated utilities an unfair advantage and eliminates consumers' choice in DER providers. Utilities have access to customer and physical network information that would be an unfair advantage. Further, many companies that are unable to rate-base have established business models to provide DER to customers. The Commission should seek to enhance the existing competitive market, which ultimately benefits consumers through choice, innovation and lowering costs.

h. *How can rates best be structured to equitably share system benefits among participating and non-participating customers (i.e. customers without DER onsite)?*

Customers without onsite DER do benefit from customers with onsite DER. These benefits would be optimized if utilities or a DSPP would plan for increased DER as an alternative to additional utility capital investments. As stated previously, Con Edison's proposal for 52 megawatts of DERs that would delay the need to build a new substation in an amount over $1 billion.[29] In addition, this proposal, which recognizes the value of DER as an alternative to traditional utility capital upgrades, only weighs system benefits. This model should be expanded throughout New York with additional consideration of environmental benefits and other public policy goals of the Commission.

7) Standby rates

b. *How can the current standby rate design be revised to reflect environmental or system values of certain types of DER?*

In its paper, Staff cites that "the current project in-service deadline for qualifying for the exemption from standby rates is May 31, 2015." The growth of the solar PV industry in New York is, in part, due to the fact that customers are exempt from standby charges. CHP developers cite stand-by charges as among some of the greatest barriers to market growth in New York State. Even with the potential implementation of several components of REV proposed by Staff, we strongly urge the Commission to extend the exemption of standby charges for solar PV beyond the in-service deadline in 2015. To the extent there are standby charges assessed on DER, it should be modified to account for diversity at a planned and targeted deployment level, with lower assumed required backup capacity for resources which are procured upstream and lower back-up to the extent the needs for supplemental grid service can be predicated and planned for.

[29] "Con Edison Seeks to Avoid Building $1 Billion Substation" http://www.bloomberg.com/news/2014-06-27/con-edison-seeks-to-avoid-building-1-billion-substation.html

d. *How should the prices for products and service reflect the additional system and environmental values represented by technologies that are currently eligible for net metering?*

The following statement is included in the Staff REV document: "Net metering can help to defray a customer's cost of installing DER and serves as a rough proxy to compensate the customer for the value that the DER is contributing to the system. A DSPP market for DER could, in time, replace the function provided by net metering, as market prices reflect the additional system and environmental values represented by technologies that are currently eligible for net metering. In this manner, the function now served by net metering can be performed with greater efficiency and the need for standby exemptions and volume caps could be eliminated."

We commend Staff and the PSC on contemplating these issues and the related concerns of several stakeholders regarding the equity and value of net metering, however we urge the Commission to preserve and extend net metering in its current form. Customers should have the right to reduce their demand through self-generation with net metering. Beyond load reduction with net metering, benefits, such as voltage regulation or the ability of a DSPP to control generation of these systems should be in addition to the benefits a consumer already receives. Further, the benefits of PV systems with net metering have been shown to approximately equal the costs when taking into account the value of reduced greenhouse gas emissions, avoided energy and capacity costs, avoided regional transmission costs, deferment of transmission and distribution capital investments, market price suppression, and others.[30] A hyper-engineered market that quantifies and sets pricing for the system and environmental benefits provided by technologies eligible for net metering would likely be complex and arbitrary, and would result in less market certainty for customers deciding whether to invest in DER. Finally, any determinations about the relative cost and benefits of NEM must be predicated on empirical evidence obtained through an open, transparent, independent third-party process that encourages robust market participant involvement.

[30] See notes 20-25

Conclusion

SolarCity understands that Reforming the Energy Vision is about fundamentally changing the way energy is produced and delivered in New York, shifting towards a more decentralized, clean, transparent and resilient model at the distribution level. To that end, we believe that all options should be on the table, including a design where (1) the key planning, market and system operations of a DSPP are performed by an independent entity or entities, similar to the independent transmission system operator model and (2) distribution utilities are incented to facilitate the deployment of DER by third-parties as directed by consumer choice, but not own DER. SolarCity recognizes there would be practical challenges towards transitioning towards this model, or any fundamental reform, but believes this independent structure would ensure better alignment between the DSPP providers and public policy objectives, and increase the likelihood of achieving the Commission's long-term vision.

In closing, SolarCity strongly supports the Reforming the Energy Vision proceeding. We appreciate the opportunity to provide comments on these policy issues and look forward to continued engagement on these important issues.

Respectfully submitted,

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